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APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZATION AND RELATED RELIEF FOR THE ACQUISITION OF WIND GENERATION FACILITIES	§ § § § § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

FILING CLERK

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

OCTOBER 14, 2019

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-1:

Provide the forecasted annual energy production and average delivered cost of energy ($/MWh) produced from each of the proposed wind energy facilities for each year the forecasted life of the facilities, with PTCs separately identified.

Response No. 2-1:

The average energy production (P50) is expected to be 3,794 GWh for Traverse, 1,127 GWh for Maverick, and 803 GWh for Sundance. SWEPCO would receive 54.5% of these amounts. The Company computed annual delivered cost of energy $ per MWh for each facility during the screening phase of the project. Screening model workpapers, which show PTC's separately, were provided in TIEC_1_19_Confidential_Attachment_2 in the Company's response to TIEC 1-19.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-2:

Provide SWEPCO's actual total native system energy sales by month for each of the last five calendar years and as forecasted for the first ten years of the base case modeling analyses supporting the proposed wind energy facilities.

Response No. 2-2:

See CARD_2-2_Attachment_1.xlsx.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-3:

Provide any benchmarking analyses conducted to assure that models used for SWEPCO's analyses of the Proposed wind energy facilities are accurately simulating the operations and production costs of SWEPCO's resources within the SPP market.

Response No. 2-3:

The PLEXOS model has been used and accepted in IRP and fuel factor filings in Oklahoma, Arkansas, Texas, Louisiana, Indiana, Ohio, Michigan, Kentucky, West Virginia and Virginia. CARD 2-3 Attachment 1 provides results of benchmarking conducted by AEP in 2010, when the Company first began using the model. That analysis compared the eastern AEP system in the PJM integrated market. At that point in time, the SPP was not an integrated market.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-4:

Provide the annual average equivalent availability, net heat rate and capacity factor for each SWEPCO generating unit for each of the last five calendar years, and as reflected in the Company's modeling analyses of the proposed wind energy resources.

Response No. 2-4:

The information responsive to this request is CONFIDENTIAL under the terms of the Protective Order. The Confidential information is available for review at the Austin offices of American Electric Power Company (AEP), 400 West 15th Street, Suite 1520, Austin, Texas, 78701, (512) 481-4562, during normal business hours

See CARD 2-4 Confidential Attachments 1 and 2 for the requested confidential information.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-5:

Provide the estimated SPP firm capacity credit for each of the proposed wind energy resources for each year of the base case analysis supporting selection of the facilities.

Response No. 2-5:

The Company used the SPP planning assumption which was in effect at the time of the completion of the screening phase of the project, which led to the selection of the three proposed facilities. This was 5% of nameplate for the first 3 years and then 15% thereafter. For Traverse (1,000 MW nameplate) this amounted to 50 MW for the first 3 years and 150 MW thereafter. For Maverick (288 MW nameplate) this was 14 MW for the first three years and 43 MW thereafter. For Sundance this was 10 MW for the first three years and 30 MW thereafter. SWEPCO was assumed to receive 54.5% of these amounts.

Note that capacity value assumptions were not an input into the levelized cost of energy that was used to rank each project vs the other projects. Capacity value was calculated, but not used in project rankings since all facilities were assumed to be subject to the same SPP capacity credit criteria.

See also the response to CARD 3-17 for a discussion of the capacity credit assumptions used in the customer benefits modeling.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-6:

Provide the estimated value of capacity of the proposed wind energy resources as reflected in the Company's economic modeling supporting the proposed wind resources in this case.

Response No. 2-6:

As described on pages 19-20 of Company witness Torpey's testimony, the Company valued the capacity based on the savings customers would receive because other capacity resources could be delayed by the addition of this resource. The Company computed different capacity values for each of the different cases. Each of the different fundamental forecasts would be expected to result in different optimal future capacity resource plans. Line 3 of the various cases presented in Errata Exhibit JFT-3 show the capacity value in each case.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-7:

Provide the ancillary service costs incurred for existing SWEPCO wind energy resources for each of the last two calendar years.

Response No. 2-7:

Please see CARD 2-7 Attachment 1.

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Prepared By: Edward J. Locigno	Title: Regulatory Analysis & Case Mgr
Sponsored By: Jay F. Godfrey	Title: VP Energy Mktng & Renewables

SPP Ancillaries		
Wind Farm	2017	2018
Canadian Hills I	$24,905	$33,952
Canadian Hills II	$22,206	$30,528
Canadian Hills IV	$40,472	$64,054
Flat Ridge 2a	$15,586	($8,613)
Flat Ridge 2b	$42,144	$11,598
Majestic I	$64,004	$81,839
Majestic II	$32,461	$53,318
Grand Total	$241,778	$266,676

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-8:

Provide forecasted ancillary service costs for the proposed wind energy resources as included in each of the first ten years of the base case economic analyses supporting selection of such resources.

Response No. 2-8:

Ancillary Service obligations are allocated to customers on the basis of load and will not change with the introduction of additional resources to the company's fleet. As a result no change, positive or negative, to the cost of ancillary services was included in the economic analysis.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-9:

Provide workpapers supporting SWEPCO's O&M cost projections for the proposed wind energy resources.

Response No. 2-9:

The information responsive to this request is HIGHLY SENSITIVE under the terms of the Protective Order. The Highly Sensitive information is available for review at the Austin offices of American Electric Power Company (AEP), 400 West 15th Street, Suite 1520, Austin, Texas, 78701, (512) 481-4562, during normal business hours.

Please see CARD 2-9 Highly Sensitive Attachment 1.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-10:

Provide the basis for expected useful lives of each of the proposed wind energy resources.

Response No. 2-10:

The information responsive to this request is HIGHLY SENSITIVE under the terms of the Protective Order. The Highly Sensitive information is available for review at the Austin offices of American Electric Power Company (AEP), 400 West 15th Street, Suite 1520, Austin, Texas, 78701, (512) 481-4562, during normal business hours.

Company witness DeRuntz discusses the Selected Wind Facilities' design life at pages 18-19 of his direct testimony.

A 30-year design life was a requirement included in Section 4.1 and Appendix E (AEP Wind Generation Facility Standards) of the RFP. The RFP is included as Exhibit JFG-1 to Company witness Godfrey's direct testimony. The Company also required that proposals include a Turbine Specific Site Suitability Report, which is a Mechanical Loads Analysis (MLA) for GE turbines, in Sections 3.8 and 9.1.11 of the RFP. Please see CARD 2-10 Highly Sensitive Attachments 1 through 3 for the MLAs for the Selected Wind Facilities that support the 30-year design life.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-11:

Provide SWEPCO's system weighted average cost of fuel and purchased energy expressed on a $/MWh basis for each of the last five calendar years and as forecasted for each year of the study period as reflected in the Company's base case analyses supporting the proposed wind energy resources.

Response No. 2-11:

See CARD 2-11 Attachment 1.xlsx

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-12:

Provide any analysis conducted by SWEPCO that quantifies the estimated fuel diversity benefit of the proposed wind energy resources.

Response No. 2-12:

Please refer to the Company's response to TIEC 1-15, specifically the IRPs contained in Attachments 1 and 2. See Section 5.4.1 of each IRP for the results of the risk analysis performed by the Company, comparing a portfolio with no renewable resources to the Company's Preferred Plan.

As stated in its response to TIEC 2-27, through its Integrated Resource Planning (IRP) process, SWEPCO evaluates various generating technologies to meet its SPP capacity obligation and energy needs, to provide a plan at least reasonable cost to its customers. Each technology includes estimates of its total cost and performance characteristics. Within the IRP model these are evaluated to a least cost plan. Various plans are developed based on varying load and commodity price forecasts and potentially other factors. For example, the Company may constrain the selection of a natural gas fired combined cycle unit to see what the model picks when this technology is not available.

In general, when the Company can diversify its fuel mix and lower cost to customers this is a relatively clear decision, due to the benefit that is provided by relying upon more than one, single fuel type. However, if diversifying its fuel mix will raise cost to customers, SWEPCO assesses whether there are any additional benefits to associate with the "diverse" addition to rationalize the additional cost. For example, this may include improved reliability over the non-diverse alternative due to the location on the grid or technology characteristics, such as fast responding battery storage versus a natural gas combustion turbine.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-13:

Describe and provide documentation of other natural gas price hedging programs previously implemented or proposed by SWEPCO or its affiliates and discuss the regulatory treatment of costs of such programs.

Response No. 2-13:

SWEPCO's proposed acquisition of the Selected Wind Facilities is not part of a natural gas hedging program. Witness Brice and Pfeifenberger merely state in their direct testimony, that in addition to other benefits, these wind assets will provide a hedge against price volatility of generation fuels and related market power prices.

SWEPCO is required to participate in a Gas Hedging Pilot Program pursuant to an LPSC order attached as CARD 2-13, Attachment 1. SWEPCO's participation in this program was approved pursuant to an LPSC order attached as CARD 2-13, Attachment 2.

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BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION

GENERAL ORDER R-32975
LONG-TERM NATURAL GAS HEDGING PILOT PROGRAM

Docket No. R-32975. Louisiana Public Service Commission, ex parte. *In re: Examination of long-term natural gas hedging proposals.*

(Decided at Open Session held June 24, 2015)

A. Background:

Pursuant to the August 21, 2013 Louisiana Public Service Commission ("Commission" or "LPSC") Notice of Rule Making, the Louisiana Public Service Commission Staff ("Staff") opened the above-captioned docket with the following goals:

> [T]o consider whether it is in the public interest for LPSC-jurisdictional investor owned utilities[[1]] to accept long-term (five, seven, ten and fifteen year), fixed-price hedging proposals for natural gas supply contracts. If so, Staff is to determine and/or develop an appropriate methodology for expedited, streamlined Commission approval of such contracts. In the course of its investigation into these matters, Staff should specifically consider examples of streamlined approval processes adopted by other jurisdictions. If it should then be determined that an expedited, streamlined approval process is in the public interest, Staff will specifically seek to establish a clear definition of a "fixed/all-in/totally inclusive price."[2]

Notice of this rulemaking was published multiple times by Staff with additional issues included for comments in the subsequent notifications.

Staff was charged with taking such steps as reasonably necessary to ascertain relevant information necessary to support the Commission's ultimate ruling in this Docket. Detailed questions and on-site interviews on the feasibility, costs, and benefits of long-term, fixed-price natural gas procurement were obtained from investor owned electric utilities (singularly referred to herein as an "Electric IOU" and collectively referred to herein as "Electric IOUs"), natural gas local distribution companies (singularly referred to herein as an "LDC" and collectively referred to herein as "LDCs"), natural gas suppliers (singularly referred to herein as a "Supplier" and

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1 The term "utility" is applied to both investor owned electric utilities and natural gas distribution companies.

2 LPSC Docket No. R-32975. Louisiana Public Service Commission, ex parte, *In re: Examination of long-term natural gas hedging proposals*, *available at* http://lpscstar.louisiana.gov/star/portal/lpsc/page/docket-docs/PSC/DocketDetails.aspx (last visited Sep. 3, 2014).

collectively referred to herein as "Suppliers"), interstate and intrastate pipelines ("Pipelines"), and natural gas financial traders ("Traders") (collectively the above categories are referred to as "Intervenors", "Stakeholders", or "Parties"). These interviews were capped by a technical conference held on May 29, 2014 at the LPSC's Baton Rouge office. As a result of Staff's interviews with the Parties in this Docket, as well as of the discussions had by and amongst the Parties at the technical conference held on May 29, 2014, Staff issued its First Proposed Draft Rule and Proposed Order to the service list for their review and comments on January 26, 2014. This First Proposed Draft Rule and Proposed Order was followed by a subsequent technical conference held Tuesday, March 10, 2015 at the LPSC's Baton Rouge office. Intervenors submitted comments on Staff's First Proposed Draft Rule and Proposed Order on March 31, 2015. After reviewing all comments filed in this Docket, Staff issued its Second Proposed Draft Rule and Proposed Order on April 28, 2015. Intervenors were again encouraged to submit comments on Staff Second Proposed Draft Rule and Proposed Order, the due date for which was May 12, 2015. Following Staff's review of Intervenors' comments on its Second Proposed Draft Rule and Proposed Order, Staff issued its Final Proposed Draft Rule and Proposed Order on June 10, 2015.

B. <u>Jurisdictional Statement:</u>

The Louisiana Constitution, Article IV, Section 21(B), provides:

> The [C]ommission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by law. It shall adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties, and shall have other powers and perform other duties as provided by law.[3]

C. <u>Results of Interviews with Stakeholders and Technical Conference Held May 2014:</u>

The purpose of this section is to recount and summarize, by issue or topic, discussions had during Staff's interviews of Electric IOUs, LDCs, Suppliers, Pipelines, and Traders, as well as those discussions had during the technical conference held on May 29, 2014.

1. <u>Staff Analysis:</u>

No Electric IOUs or LDCs interviewed currently have long-term, fixed-price natural gas procurement programs. All Electric IOUs and LDCs interviewed employ short-term or seasonal

3 La. Const. art. IV, § 2(B).

hedges to mitigate winter price volatility in natural gas. For example, both Entergy Louisiana, LLC ("ELL") and Entergy Gulf States Louisiana, L.L.C. ("EGSL") hedge 33% of winter natural gas purchases with indexed contracts and swaps to convert the indexed contracts to fixed-price contracts. However, Parties interviewed seemed to be of a general consensus that inclusion of long-term, fixed-price natural gas procurement as a component of a fuel portfolio for electric and natural gas utilities may be in the public interest, provided that the right conditions are met.

The sections below detail the complexities associated with long-term, fixed-price natural gas supply contracts, as voiced by the Parties interviewed, by dividing the major issues involved into the following components: (a.) potential benefits and costs to Louisiana ratepayers; (b.) contemporary natural gas prices; (c.) natural gas demand, Louisiana natural gas resources, and infrastructure; (d.) procurement and supply obstacles associated with long-term, fixed-price contracts; and (e.) LPSC expedited review, transparent criteria for selection, confidentiality in contract negotiations, prudency, and irrevocable contract status once approved.

a. <u>Contemporary Natural Gas Prices</u>

1. Natural gas prices have been, in historical terms (deflated prices), low in recent years (and very low in the last year)[4] and are projected to remain relatively low according to most current analyst estimates.[5] However, lower natural gas prices lead to increases in natural gas exports and demand, which place some upward pressure on natural gas prices.[6]

2. In spite of the low profile risk on the long-term forward curve, most gas used by Electric IOUs and LDCs is purchased with very short-term contracts; day ahead, with base load being purchased 30 days out – a potentially higher risk strategy than long-term, fixed-price procurement when specifically considered in light of historical price fluctuations, such as those experienced with the recent winter run up in prices due to unseasonably cold temperatures.

[4] Henry Hub ("HH") Price (NYMEX 55/28/2015) \$2.54. (\$2.28 - 2011 dollars).

[5] *But see* U.S. Energy Information Agency, *Annual Energy Outlook 2015 (DOE/EIA-0383(2015))*, *available at* http://www.eia.gov/forecasts/archive/aeo15/pdf/0383(2015).pdf, at 76 (*stating*: "Projections of natural gas prices are influenced by assumptions about oil prices, resource availability, and natural gas demand. In the Reference case, the Henry Hub natural gas spot price (in 2013 dollars) rises from \$3.69/million British thermal units (Btu) in 2015 to \$4.88/million Btu in 2020 and to \$7.85/million Btu in 2040 (Figure ES2), as increased demand in domestic and international markets leads to the production of increasingly expensive resources.").

[6] U.S. Energy Information Agency, *Annual Energy Outlook 2015 (DOE/EIA-0383(2015))*, *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf, at Figure MT-22.

b. Louisiana Natural Gas Demand, Resources, and Delivery Infrastructure

1. Natural gas has a history in helping to build Louisiana, and it's likely to be a large part of the State's future.
2. Demand by electric generation, petrochemical, and liquid natural gas exports is expected to result in double-digit growth for Louisiana natural gas consumption.
3. Recently-proposed Environmental Protection Agency ("EPA") regulations of carbon emissions could potentially result in retirement of older coal-fired electric generation facilities in both the South and Midwest.
4. Efficient, low-CO_2-emitting combined cycle natural gas generation is expected to fill this generation gap.
5. Louisiana Electric IOUs are members of both the Midcontinent Independent System Operator ("MISO") and the Southwest Power Pool ("SPP") regional transmission organizations ("RTOs"). These RTOs open up the possibility that natural gas electric generation will be used to export electricity to fill the void from retirement of older coal-fired generation in the Midwest and Mid-South.[7]
6. Liquid natural gas export facilities are currently being built in southern Louisiana. Cheniere Energy's Sabine Pass facility, for example, is expected to be the first to liquefy natural gas produced in the Lower 48 states for export.[8] The facility has a total liquefaction capacity of three (3) billion cubic feet of natural gas per day (bcf/d) and is scheduled to come online in stages beginning in late 2015. These exports facilities will greatly increase natural gas demand when they come on line.
7. America's Natural Gas Alliance ("ANGA") predicts that the Southeastern United States, including Louisiana, will import three (3) bcf/d by 2024.[9]

[7] The U.S. Energy Information Administration's *Annual Energy Outlook 2014* Reference Case projects that a total of 60 gigawatts of coal capacity will retire by 2020, which includes retirements that have already been reported. MISO alone is projecting 11-16 gigawatts of coal retirement, 5 of which have already been announced.

[8] Gwynne Taraska, *U.S Liquefied Natural Gas Exports: A Primer on the Process and the Debate* (Nov. 5, 2013), *available at* http://www americanprogress.org/issues/green/report/2013/11/05/78610/u-s-liquefied-natural-gas-exports/ (last visited Sep. 29, 2014).

[9] America's Natural Gas Alliance, *Natural Gas: Smarter Power Today*, presentation delivered at LPSC Technical Conference on Long-Term Contracts, (May 29, 2014) ("ANGA Technical Conference Presentation").

8. Louisiana and its neighboring states have extensive conventional, off-shore, and shale gas supplies.

9. However, in spite of the abundance of natural gas supplies in Louisiana and its neighboring states, development of these resources has slowed significantly in recent years due to economic issues pertaining to the recovery cost of in-state natural gas relative to other, out-of-state plays and contemporary market prices.

10. As such, it may occur that forecasted increases in natural gas demand will be fed with natural gas from out-of-state plays fed through Louisiana's extensive natural gas pipeline network.

11. Louisiana has one of the most extensive natural gas pipeline networks in the world, consisting of both interstate and intrastate facilities.

12. Any large user of natural gas can even out supply variations through the use of this storage and pipeline networks.

13. Considering the increasing growth in global demand, relative to the static development of in-state supplies as a result of the costs associated with the recovery of in-state gas relative to market prices, Louisiana may stand to become a net importer of natural gas, thereby taking advantage of the State's robust natural gas pipeline networks and extensive natural gas storage capacity.[10]

14. Interstate pipelines, originally built to flow natural gas from Louisiana to the Eastern Seaboard, are being reversed as gas production in the Marcellus shale of the Northeast U.S. has resulted in surplus production.[11] With a surplus natural gas market in the Northeast and a potential deficit of economically recoverable natural gas in Louisiana, natural gas flow may result in reversing the transportation of natural gas down the East Coast to Louisiana.[12]

15. Despite an abundance of supply, the natural gas market remains volatile. Henry Hub ("HH") spot prices have increased from $3.00 per MMBTU in July of 2012 to a value of $4.50 per MMBTU in June 2014, a 50% increase; prices have

[10] *See generally* ANGA Technical Conference Presentation, at 9.
[11] *See id.*
[12] *See id.*

subsequently decreased to $2.54 per MMBTU as of June 2015. Prices during the 2013/2014 winter (noted for significant temperature deviations from averages) spiked at approximately $8.00 per MMBTU. Reflecting the reversal in natural gas supply and demand, natural gas prices in New York are lower than HH.[13]

16. Natural gas prices have historically been highly volatile in the short-term, with systematic increasing price trends over the long-term, reflecting a scarce resource. However, technological advances in horizontal drilling and hydraulic fracturing have reversed these trends.[14] It is difficult to make any forecast of future commodity prices, and natural gas would lead the pack in the uncertainty involved in forecasting. *Attachment A* indicates a 10 year projection on natural gas prices as indicated in New York Mercantile Exchange ("NYMEX") futures delivered to HH. Many Electric IOUs and LDCs have commented that futures contracts are not a reliable indicator of physical gas deliveries, because the futures markets for contracts ten (10) years out are characterized as very "thin," in that there is not enough trading commitments to reliably predict prices. Other long-term price forecasts can be obtained through private consulting services such as IHS-CERA.

17. Using a discount rate of 8%, the levelized cost of ten (10) years of natural gas NYMEX futures is approximately $4.50 (May 2014).[15]

18. Natural gas supply should be adequate for the expansion in demand. However, because of the increased demand and reliance on imported natural gas from the Northeast, local natural gas spot prices and basis relative to national markets may become increasingly more sensitive to supply disruptions. Long-term contracts

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[13] U.S. Energy Information Agency, *Natural Gas Weekly Update for the week ending June 18, 2014* (Jun 19, 2014), *available at* http://www.eia.gov/naturalgas/weekly/archive/2014/06_19/index.cfm.

[14] *But see generally* Mason, Inman, *Natural Gas: The Fracking Fallacy*, NATURE (Dec. 4, 2014), at 28–30, *available at* https://github.com/the-frack-lab/data/wiki/Nature-feature-%22The-Fracking-Fallacy%22 (suggesting that the hydraulic fracturing boom in natural gas production may not last and that production from the most prolific fields may decline within the next ten to fifteen years; if this scenario proves accurate, natural gas prices may rapidly rise in the midterm future of ten to fifteen years).

[15] The levelized price of the asset value for a long-term, fixed-price contract can be estimated by taking a forecasted price projection and converting it to the present value over the term of the contract then amortized (as in a loan) into equal annual amounts. A more simple procedure is to average forecasted prices over the term; however, this approach would not technically be correct because the calculation ignores the time value of money.

are a way of partially ensuring stability in order to mitigate the risk of price volatility for ratepayers.

19. Appropriately structured and properly implemented long-term, fixed-price natural gas procurement plans may be an effective way to mitigate forecasted natural gas price volatility risks to ratepayers associated with expected increases in natural gas demand. Such increases are presently anticipated to be satisfied through quantities of natural gas imported from the Northeastern United States.

c. **<u>Long-term, Fixed-Price Natural Gas Procurement as a Component of Fuel Portfolios</u>**

1. Prudence of long-term, fixed-price contracts:

   i. A major issue identified in is that there may be little or no incentive for Electric IOUs or LDCs to engage in the risks associated with long-term contracts.

   ii. Current natural gas spot and short-term market risks are all borne by the ratepayer through the Fuel Adjustment Clause ("FAC").

   iii. Some stakeholders are concerned that long-term contracts may be subsequently reviewed by a later panel of the Commission and judged to be imprudent.

2. Long-term, fixed-price contract flexibility:

   i. Long-term contracts can reduce an Electric IOU's or LDC's scheduling flexibility.

   ii. Electric generation follows a load curve. Only baseline generators are run full time. Intermediate generators, consisting of mostly natural gas generators, are only run during high demand periods. As such, gas delivery must conform to a pattern of hourly and locational procurement. For this reason, some of the Electric IOUs and LDCs interviewed indicated that they currently use as many as 12-15 primary suppliers.

   iii. Long-term contracts are not flexible in delivery terms and do not synchronize with the load demand of natural gas generators. Long-term contracts are for a fixed daily volume, meaning that, unless structured otherwise, an Electric IOU or LDC would have to take a 24/7 natural gas supply under a long-term, fixed-price contract.

iv. Storage options and packing capabilities of pipelines offset flexibility concerns of Electric IOUs and LDCs. Fixed pricing is only that – a pricing arrangement. Reliable supply that conforms to the delivery requirements for variable generation can be obtained through storage, albeit with a five percent (5%) to ten percent (10%) increase in delivery costs. The existence of multiple pipeline options available for delivery and/or re-routing can also serve to mitigate surpluses of unused supply by facilitating the resale of excess gas supplies.

v. Long-term price stability can be achieved through financial hedges and swaps. Financial hedges are able to yield far more flexibility, because futures and swaps do not need to be tied to specific pipelines and/or supply sources. Furthermore, most financial hedges can be easily terminated with offsetting contracts.

3. Power-day, gas pipeline day:

i. Power day markets do not align with the gas day markets. Forward markets in the MISO and SPP RTOs make gas procurement for specific generators uncertain because Electric IOUs and LDCs are unable to predict whether the generator will be selected on a given day. A corollary to this is that gas markets close at a different time relative to electricity markets, making it uncertain whether the gas will be used.

ii. Any mandatory long-term gas stabilization efforts would need to correlate with the actual gas procurement practices and procedures of Electric IOUs and LDCs.

iii. Long-term contracts are not flexible in delivery and do not synchronize with the load demand of natural gas generators.

iv. FERC intends to address the spot market sequencing problem in the above issues.

4. Counter-party risk:

    i. Long-term gas rate stabilization involves substantial counter-party risk because there is increased risk that one party will not fulfill contract obligations or default.

    ii. This risk can be mitigated by the financial strength of the parties. With large, creditworthy parties, the impact of this risk may be de minimis.

    iii. However, with less creditworthy parties, underwriting by large brokerage houses may be required, with the consequence that the contract becomes multi-party with intermediaries adding to the cost of natural gas.

5. Financial concerns:

    i. Long-term, fixed-price contracts would necessarily contain premiums relative to current spot prices. Other long-term gas rate stabilization efforts involve other potential increased costs. Given the projected low cost of future gas supplies, many of the interviewed parties questioned whether known premiums and costs would be worthwhile as a hedge against potential unknown price increases.

    ii. A related issue is that a fixed-price contract would have to be competitive with NYMEX futures, colloquially referred to as the future curve. There do not seem to be any offers less than that pricing framework. Futures are not comparable to long-term, fixed-price contracts, because the contract would involve multiple and sequenced contracts, known as strips.

    iii. Long-term, fixed-price contracts and hedges require collateral in the form of cash working capital, increasing the cost of gas or credit support, which may not be an Electric IOU's or LDC's most efficient use of capital.

    iv. Similar to counter-party risk, long-term, fixed-price contracts may require special financing arrangements and provisions for margin calls.

    v. Long-term, fixed-price contracts could impact parties' liquidity by locking up cash.

vi. The potential need to acquire storage as a means of facilitating long-term, fixed-price contracts could represent an additional cost above the commodity and transportation costs.

vii. Brokered long-term, fixed-price contracts require compliance with banking regulations promulgated pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act[16] ("the Dodd-Frank Act").

viii. There are a limited number of financial institutions that can facilitate brokered contracts.

6. Current LPSC Regulations that affect long-term gas stabilization are outlined in Attachment B.

d. <u>Review and Approval Frameworks Proposed by Interviewed Parties:</u>

1. Natural gas Suppliers suggested a two-step review process for entering into long-term, fixed-price procurement arrangements. Under the Suppliers' proposed two step review process, the LPSC would first provide a preliminary go-ahead to the framework of a specific bilateral negotiation; parties and the Commission would then follow through with final approval that would be binding on the parties and on future panels of the Commission alike. Natural gas Suppliers were observed to be against the implementation of an MBM-type RFP process for long-term procurement, because they claimed that an MBM-type RFP would thrust the Commission into the middle of negotiations. Long-term procurement arrangements are a bilateral negotiation. According to the Suppliers, the Commission's role in furthering the development of long-term procurement arrangements should be limited to developing transparent standards for review and approval.

2. Electric IOUs and LDCs also suggested that a two phase process would ensure that either an RFP process or bilateral negotiated contract would meet the Commission's standards for least cost, public interest, and prudency. The first phase would involve submission to the Commission for approval of a procurement plan. The second phase would feature a market response, and negotiations with the final contract submitted to

16 Pub.L. 111-203, H.R. 4173.

the Commission for certification. Other respondents indicated that the best way to promote long-term, fixed-price procurement would be for the Commission to set up a transparent and expedited review of contracts, but let Electric IOUs and LDCs develop the contracts through bilateral negotiations

3. Industrial Stakeholders recommended that long-term natural gas contracts or price stabilization instruments be procured in accordance with established LPSC procedures: (1) filing of an Application specifying need, type of procurement instrument and process of procurement; (2) establishment of a docket by Commission Staff; 3) procurement of an LPSC consultant 4) specifying of an intervention period and procedural schedule; (5) review of the procurement program; and (6) submission to Commission for approval and certification. Industrial Stakeholders stressed the need for transparency and the preservation of any potential intervenors' due process rights.
4. Industrial Stakeholders also strongly recommended that successful applications should be approved and certified, but not "deemed prudent."

e. **<u>Request for proposal versus bilateral negotiation:</u>**

1. Few respondents expressed enthusiasm for a mandated RFP process to obtain long-term, fixed-price procurement; however, regulators in Oklahoma and Colorado have noted that an RFP process is the only method, short of explicit incentives or mandated thresholds, to kick start long-term, fixed-price procurement proposal negotiations. Electric utilities enter into PPAs for both short-term energy and long-term capacity through a Commission reviewed RFP process as standard operating procedure. Capacity contracts can have extended terms of five (5) years or longer.
2. As previously noted, Suppliers of natural gas suggested that lengthy review of long-term, fixed-price procurement proposals will effectively eliminate the possibility for achieving such contracts because of changing market conditions.
3. Industrial Stakeholders stated that bilateral applications, should require a hearing on the Application to proceed, as well as a certification proceeding for any subsequently completed contract proposals, with ability for intervenors to participate in both stages.

D. <u>Staff Findings:</u>

1. Although all Louisiana utilities use natural gas as a major, if not primary, fuel source, there are other alternatives in a fuel portfolio, such as nuclear generation, renewable energy sources, and coal. Natural gas is only a component of the fuel portfolios of Electric IOUs. Furthermore, although fuel is a significant component of the utility costs, fixed and other variable costs (which are recovered through the FAC) constitute the majority portion of costs recovered in the ratepayer's bill. Total fuel is approximately 33% of a typical electric utility's costs, and 40% of an LDC's costs.[17] There is risk associated with natural gas hedging. The premium of a long-term natural gas procurement program, which reflects this risk (in the form of option premiums or the upfront cost of some other gas cost stabilization instrument, relative to the spot natural gas price), is the immediate known cost impact on a consumer bill. Currently, this premium cost would be a small component of a total bill. For example, a $0.50 premium over a $4.00 spot price could be expected to have a 0.8% immediate cost impact for a residential electric utility bill and a 1.6% cost immediate cost impact for a LDC utility bill.[18] That immediate cost impact would then typically remain constant for the term of the long-term procurement program.[19] As time passes, the alternative cost of the spot market-purchased gas may either be higher or

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[17] Fuel costs as a percent of a total bill (residential) can vary considerably between utilities and also depending on locational and temporal prices for natural gas. These estimates are approximate and based on residential Cost of Service Analysis provided in the Entergy Companies' two recent base rate applications. *See* LPSC Docket No. U-32708, Entergy Louisiana, LLC, ex parte, *In re: Application for Authority to Change Rates, Approval of Formula Rate Plan and for Related Relief.* Dir. Test.Myra L. Talkington (Feb 15, 2013), ELL Exhibit MLT-6; *see also* LPSC Docket No. U-32707, Entergy Gulf States Louisiana, L.L.C. ex parte, *In re: Application for Authority to Change Rates, Approval of Formula Rate Plan and for Related Relief.* Dir. Test Rudolph Phillip Griffin (Feb. 15, 2013), Exhibit RPG-6; *see also* American Gas Association, Energy Analysis, *What Am I Paying for in My Natural Gas Bill?*, EA 2011-06 (May 31, 2011), *available at* https://www.aga.org/sites/default/files/legacy-assets/Kc/analyses-and-statistics/studies/Documents/What-Am-I-Paying-for-Gas-Bill.pdf.

[18] The immediate bill impact would be measured through the FAC or PGA. Since the alternative to the contract would be a spot or short-term purchase, the bill impact essentially would be the contract premium. By way of a hypothetical example, a $0 50 premium compared to a spot price of $4.00 would represent a 16% increase over spot for that portion of the natural gas purchase. Natural gas is only a fraction of the total fuel portfolio cost; in Louisiana typically natural gas represents 50% to 80% of total fuel costs for electrical utilities. Assuming a 75% natural gas fuel cost portfolio and of that 20% in long-term, fixed-price contracts, the premium cost impact of long-term, fixed-price would represent a 2.4% increase in immediate <u>fuel costs</u> ((16% x 75%) x 20%). For an LDC, natural gas is 100% of the PGA, so the premium impact on fuel costs would be 3.2% (16% x 20%). However, fuel costs are only a fraction of the consumer bill, approximately 33% for Electric Utilities' and 40% for LDC's residential bills. The total residential bill impact would be 0.8% (electrics: 33% x 2.4%) to 1.2% (LDC: 40% x 3.2%) depending on the utility and other conditions. Industrial Stakeholders noted that fuel costs are a higher percentage of the total bill for industrial customers, typically constituting 60% or more of the bill costs. Thus the impact of the risk premium can be very significant.

[19] An exception would be a cost escalator in the contract.

lower in future time periods, compared to the long-term procurement price. However, any variance in price relative to the spot market-purchased gas would only be an abstract comparison—not affecting the actual bill. As recently as 2008, natural gas prices increased to over $10 per thousand cubic feet ("MCF").[20] The potential cost savings of a $4.50 long-term, fixed-price contract compared to spot market purchases would be significant in these circumstances -- as much as 5% for a typical residential electricity utility customer's bill, and up to 8% for a typical residential LDC customer's bill.[21] Conversely, a decline in spot market prices to $2.00 per MCF, historically a very low price in 2014 dollars, would result in a comparatively higher contract cost of 2.2% for electric utilities and 3.5% for LDCs measured against the spot market – that is, the contract is more expensive by these percentages.[22] These examples illustrate the risk in natural gas hedging. Seasonal variation: Long-term procurement programs can moderate the impact of price fluctuations in the natural gas market. The natural gas market has historically been characterized by wide swings in price. Even as recently as the 2013-2014 winters, abnormally cold temperatures have caused large swings in price for certain regions.

2. Systematic long-term risk: Long-term procurement programs are more than just a hedge against seasonal price variation. A five or ten-year, fixed-price contract can also counter systematic long-term increases in natural gas prices. However, several of the parties that were interviewed by Staff emphasized that long-term, fixed-price contracts or financial hedges[23] should not be considered as a method to achieve extra profits, or even minimize costs over the spot market.[24]

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[20] MCF equals the volume of 1,000 cubic feet ("cf") of natural gas.

[21] Using the same assumption as previous, a $9.00 spot natural gas price compared to a $4.50 long-term, fixed-price contract would represent a 100% increase. With the same proportional calculations as previously, (100% x 75% x 20% x 33%), the potential cost saving of an electrical bill from the long-term, fixed-price contract would be 5%. For an LDC (100% x 100% x 20% x 40%), the cost savings would 8%. All these calculations are dependent on the duration of the natural gas spot price spike.

[22] Again, this is a hypothetical comparison of what could happen if only spot deliveries were used instead of long-term, fixed-price contracts. The actual contract cost does not change.

[23] *See generally* Ken Costello, *NRRI Survey on Long-Term Gas Contracting* (Nov. 13, 2012), *available at* http://www.narucmeetings.org/Presentations/Presentation%20on%20NRRI%20survey%20on%20L-T%20gas%20contracting%20ppt%20short%20version.pdf.

[24] All risky choices such as bets can be characterized by expected value of outcomes; for instance, a coin toss is a fair expected value bet (50% win, 50% loss), whereas all casino based gaming options have negative expected values (otherwise, the casino would go out of business). Long-term, fixed-price contracts should not be considered as having a positive expected value. Their benefit derives from price stability. *See generally* Ken

3. Long-term gas procurement versus other asset acquisition: Several stakeholders have noted that a long-term natural gas procurement program may impose additional risks on ratepayers. As noted above, Staff agrees that there is risk with long-term gas procurement; however, Staff notes that most asset acquisitions on the behalf of ratepayers entail risks.[25]

4. Long-term, fixed-priced natural gas contracts are not the only type of instrument or policy that can stabilize natural gas. Alternative natural gas cost stabilization instruments include:

    a) Hedged delivery contracts are extended procurement options featuring a long-term index to fixed-price swap in conjunction with an indexed physical delivery contract.[26] Louisiana LDCs and Electric IOUs currently engage actively in seasonal and short-term hedging of their natural gas supplies. There should be no significant functional difference if these types of short-term hedges are extended to long-term deliveries. However, because of the extended timeframe for hedged deliveries and intervening events, long-term hedging requires a more consistent strategy or planning and adaptation. Long-term hedges may also have financial commitments and underwriting requirements, which may require a commitment of capital and rate base from LDCs and Electric IOUs.

    b) Futures Contracts: NYMEX or Intercontinental Exchange ("ICE") traded futures contracts and over the counter ("OTC") basis contracts are well

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Costello, *Gas Hedging: Should Utilities Do Less and Do It Differently?* (Jul. 17, 2011), *available at* http://www.narucmeetings.org/Presentations/Summer2011_Gas%20Hedging.pdf. at 5.

[25] Especially considering the RTO markets for energy and capacity, in which all Louisiana Electric IOUs participate. Consider a new gas generator; this unit, once in operation, will bid electrical energy and capacity into the day ahead and annual auction markets. To the extent bids from the generator are not accepted, the generator capacity is underutilized. This is a risk imposed on the ratepayer who is fully paying for the capacity in rate base. In fact, long-term procurement of low-cost natural gas that is associated with the acquisition of a new generation unit could actually be used to effectively hedge some of the risk of acquiring the new generator asset. Another long-term gas related asset is firm natural gas pipeline capacity. Electric IOUs and LDCs extensively procure long-term capacity contracts for delivery of natural gas through pipelines. These contracts can extend 10 to 20 years. It is of course possible to engage in non-firm, short-term contracts, but most utilities would argue this course of action would be more risky.

[26] The distinction here is between hedging prices associated with physical deliveries, versus pure price speculation (in which deliveries are never contemplated – that is, a "naked" hedge). Long-term hedges are also distinguished from seasonal hedges based on the impact to balance sheets over multiple years: for example, a long-term hedge under adverse market conditions can become a liability with ramifications for multiple years.

established instruments for mitigating price risk in natural gas. The advantage of the futures contract with a corresponding OTC basis contract between HH and a delivery point is that the contract combination provides protection from price risk, but does not have physical delivery complications.[27] However, the futures contract should always be associated with a physical amount of gas that needs to be purchased by the Electric IOU or LDC in the conduct of normal business. The combination of closing costs, or net gain, of the futures contract and the purchase of physical spot-priced gas should be the impact to the ratepayers' FAC charges or PGA charges. These types of transactions could be executed over time, and spread across a maturity curve, to reach a desired duration and quantity. Several Electric IOUs and LDCs noted that futures markets are "too thin" for contracts beyond a few years, indicating that there is not sufficient trading necessary to establish definitive pricing. Nevertheless, an LDC or Electric IOU can always test the market by soliciting a bid from potential/prospective buyers at a contract price that the Utility considers appropriate for long-term delivery, as there may be a buyer.

Staff recognizes that contracts are also subject to margin calls; nevertheless, Staff finds that a properly framed program of futures contracts purchases could potentially be a viable instrument to mitigate risk. In order to mitigate counter-party risk, OTC transactions should be exchange-cleared within a specified period of time.

c) Joint Ventures with Upstream Suppliers: Joint ventures are another means of providing long-term gas rate stability. In a joint venture, an Electric IOU or LDC partners with an experienced Supplier in the exploration, drilling and operations of a proven, or near-proven, natural gas field. The Utility provides investment capital to the Supplier in exchange for a long-term physical supply of natural gas from the field. As a partner to the

27 Futures contracts are almost always offset before physical delivery – this still provides price stability for the equivalent quantity of natural gas.

exploration, drilling or operations, an Electric IOU takes on a portion of the associated production risk. But with proven or near-proven reserves, and particularly with horizontal wells, this production risk can be readily evaluated. Joint ventures are therefore potentially less prone to price risk than spot gas purchases on the open market.[28]

Staff recognizes that there are additional instruments and/or variations of the instruments listed above that may provide long-term gas cost stability, including other forms of direct ownership in natural gas reserves, such as: non-operated working interests, royalty interests, overriding royalty interests, and volumetric production payments. Such variations, though not reviewed here, may be proposed as instruments for stabilizing natural gas costs.

5. Long-term natural gas procurement programs are not standardized acquisitions. Of the different instruments reviewed herein, each has its appropriate uses and may be better suited for different procurement procedures. Several of the parties interviewed by Staff recommended a market-based RFP process; but other parties suggested that long-term natural gas procurement programs differ from standardized contracts in the requirement for specific or bilateral negotiations. Futures contracts purchased on national exchanges require neither an RFP nor bilateral negotiations, but a submission of a standardized bid. The Electric IOU buying and selling natural gas futures on a national exchange is required to meet credit standards for the underwriting entity.[29] Thus, for the successful procurement of different gas cost stabilization instruments, three alternative procurement procedures may be necessary: (1) MBM/RFP process; (2) bilateral negotiations; and (3) credit supported bid submissions on national or OTC exchanges.

6. Natural gas suppliers are in a competitive, non-price regulated industry. Confidentiality in contract negotiations is a requirement by suppliers to preserve competitive positions and also to avoid antitrust issues.

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28 Any joint venture proposal would still be subject to a prudence review by the Commission.

29 OTC contracts also require meeting specific credit requirements by counterparties.

7. The ultimate benefit of long-term, fixed-price procurement programs, through contracts or gas cost stabilization instruments, is a significant factor in the tradeoff between the immediate cost of the instrument relative to current procurement, versus the long-term risk of variable spot prices and adverse price trends. Without extensive market research into ratepayers' preferences for stability, this tradeoff is uncertain. Thus, a policy to encourage long-term, fixed-price contracts should proceed incrementally with evaluation by the Commission after an initial implementation.

E. Staff's Recommendations:

Based on Staff's interviews with interested parties, the comments provided by intervenors, and the positions expressed at the technical conference, Staff recommends the following:

a. **Long-term natural gas procurement programs through fixed-price contracts or other natural gas cost stabilization instruments:**

The Commission should not substitute its business judgment for that of the Electric IOUs and LDCs. Long-term natural gas procurement should be considered in the context of instruments that could stabilize the cost of natural gas used as fuel for Electric IOUs, reducing the risks of sporadic natural gas price fluctuations for ratepayers. To that end, a long-term natural gas procurement program order should require Electric IOUs to explore the feasibility of potential long-term natural gas procurement programs.[30] Such an Order should not apply to LDCs.

The Commission has collectively referred to these instruments under the rubric of gas rate stabilization. As such, a long-term natural gas procurement program order should address the broader need for an array of gas procurement instruments that could provide gas cost stability to ratepayers for a period of five (5) years or more. This array of gas procurement instruments, collectively referenced to herein as natural gas cost stabilization instruments, includes, but are not limited to, the following:

[30] This is not an unprecedented approach as suggested in comments provided by ELL and EGSL. rather this is similar to the approach that was taken in the Renewable Energy Pilot Program Implementation Plan and Corrected General Order No. 7-21-10 (R-28271 Subdocket B)

1. Fixed-price, long-term delivery of physical gas to a generator or distribution gate[31];
2. Nationally or OTC-indexed contracts, with or without OTC basis contracts, with swaps or collars providing price stability;
3. Futures contracts based at HH;
4. Upstream supply acquisition and/or joint ventures at the field level; and
5. Variations on the above instruments, or additional instruments not listed that provide long-term natural gas cost stability.

b. <u>Implementation of Pilot Program:</u>

Staff recommends that the Commission implement a long-term natural gas procurement pilot program ("Long-term Procurement Pilot Program"). Implementation of a Long-term Procurement Pilot Program would allow Electric IOUs and the Commission to assess the effectiveness of a long-term natural gas procurement policy without over-committing ratepayers to a specific course of action. A three-year Long-term Procurement Pilot Program should supply sufficient data for assessment. Under this Long-term Procurement Pilot Program, Louisiana-jurisdictional Electric IOUs would be required to propose a long-term natural gas procurement program in order to attempt to secure long-term natural gas price stability through the use of one or more of the instruments outlined above. These proposals to the Commission should be made through an application process, which is outlined in detail in *Attachments D, E,* and *F* below. Participation in the long-term procurement program proposal application process shall not obligate the Electric IOUs to undertake any purchases from their respective proposed procurement programs, as it is not the Commission's desire to substitute its business judgment for that of the Electric IOUs, nor shall it obligate the Commission to approve a particular procurement of an instrument at this time. However, if a proposed long-term procurement program is not undertaken by an Electric IOU, then that Electric IOU's reasons for ultimately not undertaking its proposed procurement program should be extensively documented and submitted to the Commission. Likewise, if the Commission ultimately rejects a proposed procurement, the Commission should document its reasons for its rejection.

c. <u>Establishing portfolio minimums:</u>

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[31] Fixed/all-in/totally inclusive price.

The Commission should refrain from establishing minimum standards for Electric IOUs' fuel portfolios that are obtained with a long-term, fixed-price contract or other natural gas cost stabilization instrument. Depending on the pricing and terms of the supply proposal, it may be that purchases are determined by the Commission to not be prudent and/or in the public interest. For example, a mandated natural gas portfolio consisting of twenty-percent (20%) long-term, fixed-price contracts could potentially prove more expensive to ratepayers than current procurement policies, because implementing a mandatory twenty percent (20%) floor would box Electric IOUs into inflexible negotiating positions with Suppliers.

d. <u>Procurement Flexibility:</u>

Staff agrees with several of the interviewed parties that Electric IOUs should be allowed to undertake one or more of the long-term natural gas cost stabilization instruments according to their particular organizational structure and circumstances. Further, depending on the instrument or combination of instruments chosen, the Electric IOUs should be allowed to follow one of the following procurement methods: (1) an RFP process for fixed-price, long-term contracts and upstream supply acquisitions; (2) a bilateral negotiation for fixed-price, long-term contracts and upstream supply acquisitions; or (3) a standardized bid process on a national or OTC exchange to procure a natural gas cost stabilization financial instrument. These procurement processes are described in *Attachments D, E,* and *F* below, respectively.

e. <u>Need for Procurement Oversight:</u>

Several parties have asserted that the best procurement method would be a timely, confidential bilateral negotiation. However, a bilateral negotiation that requires confidentiality of terms can have the appearance of a non-competitive, higher-priced procurement program. An affiliate-based transaction can also have that appearance. RFPs for natural gas procurements will have specific timeframes that bind regulators to make quick decisions on matters that this Commission has not historically encountered. Long-term natural gas hedge procurements will involve the establishment of financial terms and constraints that must be analyzed for prudence. Staff and Intervenors should be involved in the stages of procurement to ensure that procurements are performed at arm's length and represent an efficient solution to natural gas cost stabilization that is in the public interest.[32] The supplier auction would be an exception since there is a competitive process involved in procurement even with a subsequent bi-lateral negotiation, as long as the parameters of the purchase in the supplier auction are outlined in the Initial Application.

f. **Application to the Commission:**

Staff recognizes that there are three valid procurement processes for long-term natural gas stabilization: 1) request for proposal ("RFP"), 2) bilateral negotiation, and 3) purchased through established exchanges or over the counter ("OTC"). Staff recommends that each procurement process have its own procedural schedule and requirements, each of which would be initiated by an application for approval of a long-term procurement pilot program that outlines, more specific details of the anticipated procurement ("Application").

Following receipt of the Application, the LPSC would initiate a docketed proceeding in accordance with the appropriate *Attachment D, E* or *F*, depending on the procurement process included in the Application and parties shall be allowed to intervene. Following submission of an Application, an Electric IOU would engage the market in accordance with the procedures provided for in the appropriate *Attachments D, E,* or *F* and attempt to confect a transaction.

g. **Request for Certification:**

Assuming that an Electric IOU is successful in finding a transaction that: (1) meets the criteria of the appropriate *Attachment D, E,* or *F* and (2) receives an Electric IOU's internal approvals, the Electric IOU would then submit a "Request for Certification" that supplies the details of any specific transaction. The Electric IOU's Request for Certification would be made in the same docketed proceeding as its Application. Staff and intervenors would perform a review of the Electric IOU's Request for Certification in accordance with the appropriate *Attachment D, E,* or *F*. Each of *Attachment D, E,* or *F* culminates with a Commission vote on

[32] Initial approval by the Commission would be required for a bilateral negotiation and/or a financial transaction. The Commission has in its discretion, as it always does, the ability to appointment an independent monitor or a consultant with expertise in natural gas, if there are questions about affiliate involvement or the bilateral negotiation has significant rate base implications (even if the rate base costs are recovered through the FAC or the PGA). Another option that could be suggested by an Electric IOU in its Application would be to obtain an opinion issued by an investment bank, or other third party expert, following the negotiation of a final transaction but prior to signing of final transaction documents. The investment bank's opinion could include a review of the marketing and negotiation process and an analysis of the merits of the transaction versus other comparable transactions.

the approval of an Electric IOU's Request for Certification. Following the Commission's vote on the approval of an Electric IOU's Request for Certification, the Electric IOU should submit a second Application ("Subsequent Application"), or third Application ("Final Application") with the Commission, which such Subsequent Application or Final Application should utilize a different natural gas cost stabilization instrument than was utilized in either the Electric IOU's Application or Subsequent Application.[33]

Provided that an Electric IOU complies with the framework provided herein. the Commission's approval of an Electric IOU's Request for Certification would determine the prudence of the terms of the transaction that was included in the Request for Certification. If the Commission determines that the terms of a Request for Certification are prudent, that prudence determination should continue in effect for the duration of the transaction at issue, and should be exempt from review or reexamination by subsequent panels of the Commission, even if the realized price of natural gas under the transaction proves to be above future spot prices. However, an Electric IOU's management of a specific transaction, in accordance with the terms approved by the Commission in a Request for Certification, should remain subject to prudence review, and the recovery of costs incurred as a result of imprudent management should be disallowed.

h. <u>Notification:</u>

If the Electric IOU is not successful in confecting such a transaction, then in lieu of filing a Request for Certification it should make a filing with the Commission (a "Notification") detailing the steps it took to procure a transaction that meets or exceeds the terms specified in its Application and why it has been unable to do so. Following an Electric IOU's filing of a Notification, that Electric IOU should submit a Subsequent Application, or a Final Application with the Commission, which such Subsequent Application or Final Application should utilize a

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[33] In no event would an Electric IOU be required to submit more than three Applications to the Commission—Application, Subsequent Application, or Final Application. The Commission's intent is merely to encourage Electric IOUs to explore the feasibility of procuring more than one type of natural gas price stabilization instrument.

different natural gas cost stabilization instrument than was utilized in either the Electric IOU's previous Application or Subsequent Application.[34]

i. Completion of Pilot:

Upon the Commission's completion of its review of a Request for Certification or Notification associated with an Electric IOU's third, Final Application, Staff should make a recommendation to the Commission on whether or not the Electric IOU has met its reasonable effort obligation under the Pilot Program. If the Commission determines, after hearing Staff's recommendation, that the Electric IOU has met its reasonable obligation effort under the Pilot Program, then the Electric IOU should be determined to have completed the Pilot Program.[35]

F. Commission Consideration:

The proposed draft General Order was filed on June 10, 2014 and considered by the Commission at its June 24, 2015 Business and Executive Session. On motion of Chairman Holloway, seconded by Commissioner Skrmetta, with Commissioner Boissiere and Commissioner Angelle concurring and Commissioner Campbell opposing, the Commission voted to adopt the Proposed General Order with the following amendments:

1) **Insert in Ordering Paragraph 2**, at the end of the first sentence: "*, or the filing of a Notification of inability to propose a procurement.*"

2) **Insert in Ordering Paragraph 2c.**, at the end of the last sentence: "*The requirement for filing up to three Applications shall not be construed as a requirement to file a Request for Certification.*"

3) **In Staff's Recommendation section E, subsection (b):** change the references from "should not" to "shall not", so that the paragraph reads: "*Participation in the long term procurement program proposal application process~~should~~ shall not obligate the Electric IOUs to undertake any purchases from their respective proposed procurement programs, as it is not the Commission's desire to substitute its business judgment for that of the Electric IOUs, nor ~~should~~shall it obligate the Commission to approve a particular procurement of an instrument at this time.*"

4) **Revise Attachment D, Paragraph A.6.** to require that the proposed supply contract be included with a certification filing, so that the sentence reads: "*Utility files either: (a) a Request for Certification, ~~detailing~~ and contract(s) seeking*

[34] In no event would an Electric IOU be required to submit more than three Applications to the Commission—Application, Subsequent Application, or Final Application. The Commission's intent is merely to encourage Electric IOUs to explore the feasibility of procuring more than one type of natural gas price stabilization instrument.

[35] The essential nature of the program is voluntary though the Commission expects reasonable effort to secure a procurement instrument.

approval (if any), with copies to Staff and Intervenors, or (b) a Notification of its inability to procure a long term natural gas rate stabilization instrument in accordance with the provisions of Section 3 of the General Order."

5) **Delete the last sentence in Footnote 42** that would create an exception to the LPSC General Fuel Order to allow costs of LPSC counsel and consultants and other review costs to be recovered through the Fuel Adjustment. Costs associated with LPSC counsel and consultants and other review costs should be part of the utility's FRP filing.

6) **Delete the sentence** in Footnotes 77, 81, 82, 85, 88, 89 that would require LPSC certification within 30 days or 60 days, which conflicts with the required minimum 30 and 60 day amounts of time that is allowed for Staff/Intervenor review of the supply proposals.

IT IS THEREFORE ORDERED THAT:

1. **Pilot.** Starting July 1, 2015, a three-year pilot program, Long-term Procurement Pilot Program, shall be established for each LPSC-jurisdictional Electric IOU.[36] Electric IOUs shall make reasonable efforts to design[37] a long-term natural gas procurement program plan that utilizes one or more of the long-term natural gas cost stabilization instruments identified herein: (1) long-term, fixed-price contracts with delivery, (2) indexed delivery contracts with price hedging, (3) futures contracts, (4) natural gas supply acquisition through a direct interest or joint ventures, or (5) another type of gas procurement instrument proposed by the Electric IOU that accomplishes significant long-term natural gas cost stability for rate payers. The long-term procurement plans developed around the instruments selected shall be designed to provide gas price stability on a portion of the Electric IOUs' fuel portfolios for a minimum of five (5) years.[38]

2. **Procurement.** Electric IOUs' Applications for Commission approval of a long-term natural gas procurement program plan shall be conducted via an Application, followed by a Request for Certification, that shall meet the requirements of *Attachment D, E* or *F*, depending on the method of procurement being applied for or the filing of a Notification of inability to propose a procurement.

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[36] If LPSC-jurisdictional affiliated operating companies and/or divisions file separate individual applications for rate adjustments, and/or have separate PGA or FAC charges, then each LPSC-jurisdictional affiliate must develop and implement its own, individual long-term procurement plan

[37] *Reasonable effort* is interpreted in this context as meaning the development and evaluation of a reasonable proposal for acquisition. The ultimate acquisition is a decision of the utility. It is not unreasonable to develop a proposal, evaluate it for risk on ratepayers considering short-term market risk and other factors, and then for the utility to reject the results of the proposal with enumerated justifications.

[38] The utilities will have discretion to propose volume parameters for their natural gas instruments with appropriate rational.

a. If an Electric IOU intends to utilize an RFP process as its means of procurement in its program plan proposal, then that Electric IOU shall proceed with doing so according to the procedures outlined in *Attachment D* herein.

b. Procurement program proposals that utilize bilateral negotiations shall proceed according to the process provided for in *Attachment E* herein. The expedited, streamlined procedures provided in the proposed rule for evaluation of long-term natural gas supply contract proposals shall not apply to evaluation or approval of any proposals to acquire ownership in natural gas reserves, either through direct ownership, joint ventures for upstream supply acquisitions or otherwise. Rather, any such utility proposals to acquire ownership in natural gas reserves shall be evaluated by the LPSC under its rules of practice and procedure. A supplier asset auction (i.e., a procurement in which the utility participates as one of several purchasers in an organized RFP conducted by a gas supplier), shall be classified and proceed as a bilateral negotiation.

c. Procurement program proposals that utilize long-term hedges or futures contract purchases on recognized exchanges shall proceed according to the process provided for in *Attachment F* herein.[39] The requirement for filing up to three Applications shall not be construed as a requirement to file a Request for Certification.

An Electric IOU shall file three Applications. Each such Application shall utilize a different natural gas cost stabilization instrument, and meet the requirements of *Attachment D, E* or *F*, depending on the method of procurement being applied for.[40]

3. **<u>Notification of inability to propose a procurement instrument for approval.</u>** An Electric IOU is under no obligation to undertake any long-term natural gas procurement program plans that it may propose. However, considering the spirit of the Pilot Program, the Electric IOU must file an Application, and it must undertake reasonable efforts to develop and evaluate a procurement process described in that Application. An Electric IOU who has used

[39] If the Commission retains special counsel and/or consultants to assist Staff in the review of an application filed pursuant to this Order, the direct costs for those counsel and/or consultants shall be borne by the submitting utility. The utility may recover the costs associated with reviewing their specific application.

[40] In no event shall an Electric IOU be required to submit more than three Applications to the Commission—Application, Subsequent Application, or Final Application. It is the not the Commission's intention to create an endless loop of applications. If after three applications, each utilizing different natural gas stabilization instruments, there is no acceptance of a procurement plan, the Electric IOU shall have satisfied its reasonable efforts obligation under the Pilot Program.

reasonable efforts to develop and evaluate a long-term gas rate stabilization instrument as provided in its Application, but who has been unable to procure an instrument pursuant to the procedures of *Attachment D, E* or *F*, shall provide a Notification of such to the Commission. The Notification filed with the Commission shall detail the steps the Electric IOU took to develop and evaluate a transaction that meets or exceeds the terms specified in its Application and the reasons for why it has been unable to procure such a transaction.[41]

4. **Certification.** The Commission acknowledges and accepts that there are risks associated with the natural gas price stability options in the event that purchase proposals are certified by the Commission pursuant to the procedures set forth in this Order. The Order's purpose is to provide a procedure for Electric IOUs to attempt to secure long-term natural gas price stability and for the Commission (with participation by the utility, Staff and Intervenors) to determine whether or not any proposal for long-term natural gas supply that are presented by a utility for certification can provide price stability at a reasonable cost and risk to the ratepayers and whether or not such proposal should be approved by the Commission as being prudent and in the public interest.

5. **Final Prudency Determination.** The Commission finds that participation in this Long-term Procurement Pilot Program is in the public interest. Specific gas cost stabilization purchases, or individual contracts that are components of an overall stabilization program, that are certified by the Commission as components of long-term procurement program may still result in adverse costs to ratepayers, compared to future spot market conditions and/or unforeseen contingencies. However, certification made pursuant to this Order implies an initial prudency determination of these purchases and contracts that cannot be subsequently overridden by adverse or unforeseen future circumstances. The Commission and/or subsequent Commissions shall not second guess purchases, contracts, or procurement programs that are certified by the Commission during the Long-term Procurement Pilot Program as being prudent and in the public interest. Nevertheless, the Electric IOUs are still responsible for prudently managing any instrument which may require prospective management.

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[41] Such Notification reasons may include the Electric IOU's inability to procure a long-term gas rate stabilization instrument that could receive its internal approval.

6. **Continuing Obligations.** This Order should not be construed to absolve or relieve any Electric IOU or competitive bidder from any duty prescribed by the laws of the State of Louisiana or the United States including, but not limited to: the federal Public Utility Regulatory Policies Act (Public Law 95-617, as amended) and any other state or federal law regarding contractual rights and obligations, antitrust enforcement or liability, or laws against improper restraint of trade or "takings" of property.

7. **End of Pilot.** Notwithstanding good cause to the contrary, Electric IOUs shall have three (3) years from the effective date of this Order to complete their obligations under this Order. After the three-year active procurement period, the Commission, in conjunction with the Electric IOUs, will evaluate the efficacy of the program and determine if it should be extended; however, such an evaluation shall not revisit the prudency or justness and reasonableness of any transactions entered into pursuant to this Order. The Commission notes that any resulting Instrument will have a minimum term of five years, and approvals and prudence determinations gained through the Pilot will continue for the life of the approved Instrument.

BY ORDER OF THE COMMISSION
BATON ROUGE, LOUISIANA
July 13, 2015

/S/ CLYDE C. HOLLOWAY
DISTRICT IV
CHAIRMAN CLYDE C. HOLLOWAY

/S/ SCOTT A. ANGELLE
DISTRICT II
VICE CHAIRMAN SCOTT A. ANGELLE

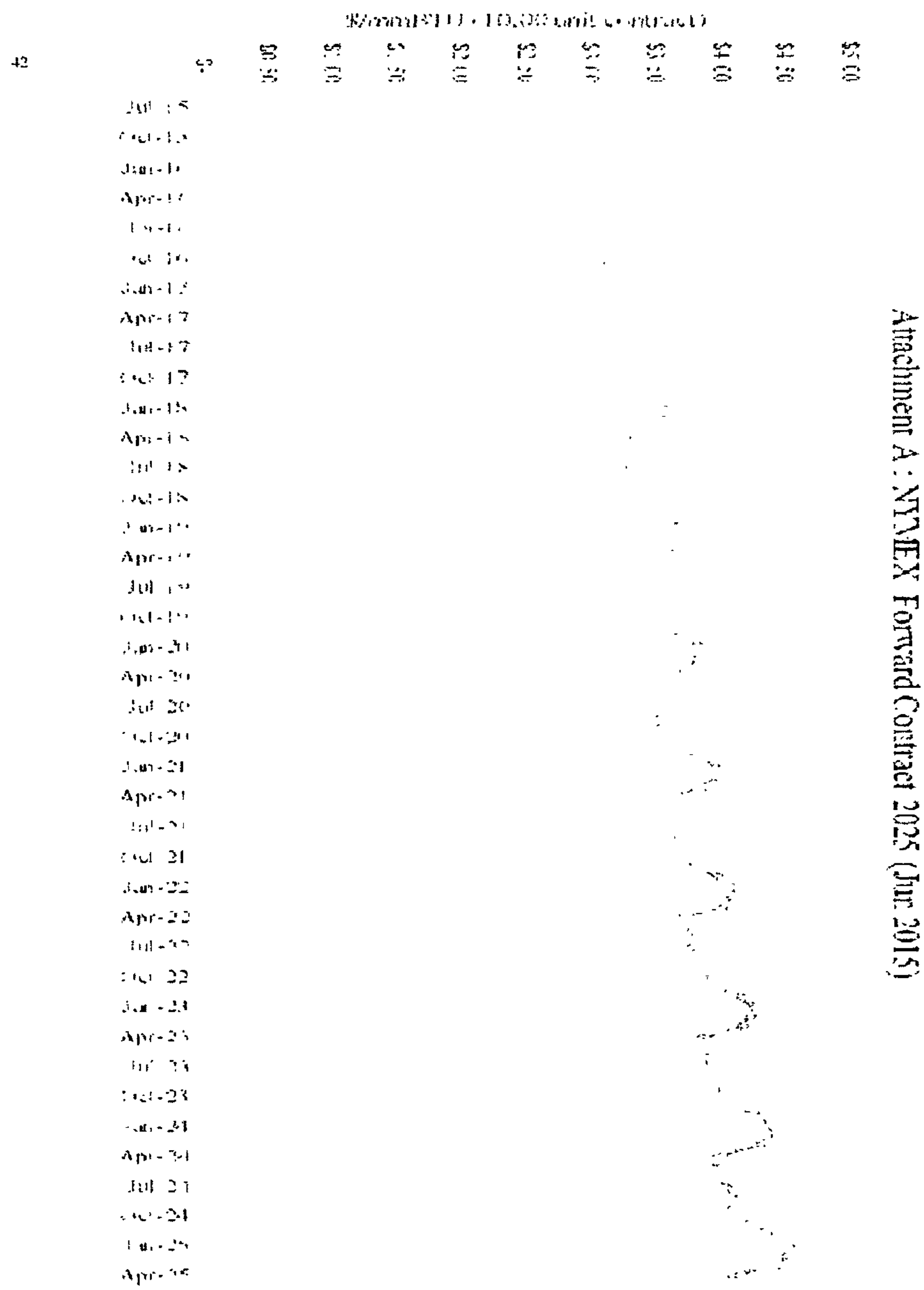
/S/ FOSTER L. CAMPBELL
DISTRICT V
COMMISSIONER FOSTER L. CAMPBELL

/S/ LAMBERT C. BOISSIERE
DISTRICT III
COMMISSIONER LAMBERT C. BOISSIERE, III

/S/ ERIC F. SKRMETTA
DISTRICT I
COMMISSIONER ERIC F. SKRMETTA

EVE KAHAO GONZALEZ
SECRETARY

Attachment A: NYMEX Forward Contract 2025 (June 2015)



[42] CME Group, *Henry Hub Natural Gas Futures Quotes*, http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html (last visited 04 June 2015).

Attachment B: Previous LPSC Orders that Affect Long Term Natural Gas Hedging

Order No. U-22407, Development of Rules, Regulations, Practices and Procedures Relative to the Weighted Average Costs of Gas Filings made by Jurisdictional Gas Utilities (1999): The Commission's *PGA General Order*[43] defines the recoverable and non-recoverable costs of natural gas purchases of LDCs that flow through to ratepayers through the Purchase Gas Adjustment Clause cost recovery mechanism ("PGA"). This Order states the following concerning hedging and financial rate stabilization instruments:

> E. Rate Stability. The Commission strongly encourages, but is not requiring, gas utilities to adopt gas procurement programs which will increase the stability of their PGA rates. The Commission is encouraging systematic, rather than speculative, approaches to rate stability. Rate stability programs may be implemented by purchasing gas directly from a supplier or through the purchase of various financial instruments. Such programs include contracting for a portion of the utility's gas supplies in advance of delivery at the then prevailing market price and the purchase of various financial instruments.[44]

Applying the definition found in the *PGA General Order*, long-term, fixed-price contracts would likely constitute "contracting for a portion of the utility's gas supplies in advance of delivery at the then prevailing market price[.]"[45] Moreover, costs recoverable through the PGA also include financial instruments, which are defined as:

> Prudently incurred costs associated with various financial instruments purchased by the gas utility to stabilize PGA rates. Includes the transactions costs associated with the purchase of futures contracts and options.[46]

The *PGA General Order* does not limit financial instruments according to time frame, although, implicitly, it most directly addresses seasonal hedges. The *PGA General Order* does, however, address prudency through the requirement of systematic audits:

> The Commission shall investigate the purchased gas costs incurred by each Group I gas utility during its designated review period for compliance with the requirements of this General Order. Each such investigation by the Commission shall result in an Audit Report. The Audit Report shall contain specific findings and recommendations concerning the utility's compliance with this General Order. The Audit Report shall be docketed. Hearings

43 GENERAL ORDER (Mar. 24, 1999). LPSC Docket No. U-22407. *In re: Development of Rules, Regulations, Practices and Procedures Relative to the Weighted Average Cost of Gas Filings made by Jurisdictional Gas Utilities* ("*PGA General Order*").

44 *PGA General Order*, at 12.

45 *Id.* at 12.

46 *Id.* at 9.

> may be held to determine if inappropriate costs have been recovered through a utility's PGA, and to address any other issues raised by the PGA filings and addressed in the Audit Report. Upon conclusion of the Commission Staff's investigation and hearings, the Commission shall enter an order approving the utility's review period purchased gas costs that it finds are eligible for recovery through the PGA mechanism. Costs approved as eligible for recovery through the PGA mechanism shall no longer be subject to review except in instances where the Commission's investigation and Audit Report were based on inaccurate information provided by the utility.... The gas costs incurred by each Group I utility will be reviewed no less frequently than every other year.[47]

The *PGA General Order* also addresses second guessing:

> The Commission will not exercise hindsight and penalize gas utilities if, through the use of best cost gas procurement policies, purchases made in advance at the then prevailing market price are priced higher than the market price at the time of delivery. Similarly, the Commission will not reward gas utilities if purchases made in advance are priced lower than the market price at the time of delivery. Just as all other purchases made by a gas utility are reviewed, advance purchases will be reviewed to ensure that a gas utility's contracting practices are prudent and reasonable. For example, advance purchases should be made at *market prices* and purchased quantities should be consistent with a gas utility's requirements and should not lead to the purchase of supplies in excess of requirements.[48]

Order No. U-21497, Development of standards governing the treatment and allocation of fuel costs by electric utility companies (1997): Order No. U-21497, which established the Fuel Adjustment Clause cost recovery mechanism ("FAC"), does not directly address long-term hedging.[49] However, two paragraphs in the *FAC General Order* could be construed as discouraging the use of financial hedges:

> All electricity consumers are ensured that they will only pay the actual cost of fuel utilized to produce electricity, no more and no less. The electric utilities are prohibited from earning a profit on their use of fuel to produce electricity... All electricity consumers are ensured that only the direct cost of fuel, and no other charges, is passed through electric company fuel adjustment clauses. This requirement will protect consumers from paying unauthorized charges and prevent utilities from accelerating the recovery of non-fuel costs.[50]

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47 *Id.* at 5-6.

48 *Id.* at 12 (emphasis added).

49 *See generally* GENERAL ORDER (Nov. 6, 1997). LPSC Docket No. U-21497, *In re: Development of standards governing the treatment and allocation of fuel costs by electric utility companies* ("*FAC General Order*"), at 17. Although long-term fixed-price contracts are not specifically addressed in the FAC Order, such contracts are direct fuel costs and thus may require a different analysis.

50 *Id.*

Nevertheless, the Commission subsequently extended rate stabilization and financial instruments to both the FAC and the PGA:

> [Several utility companies] questioned whether waivers/exceptions were required to permit recovery of costs associated with hedging mechanisms through the Purchased Gas Adjustment and Fuel Adjustment clauses. Second, they sought a waiver or exception, if necessary, to permit affiliates to participate in the bidding process to obtain hedging contracts. We believe these requests are reasonable, and to the extent necessary, waivers or exceptions are granted.[51]

Order No. U-25729, Rate Stabilization and Preapproval of Hedging and Gas Procurement Plans (2001): The Commission's *Gas Procurement Plan General Order* most directly addresses issues associated with long-term, fixed-price contracts. In Docket No. U-25729, several LDCs and electric companies sought approval of rate stabilization plans for natural gas hedging, in addition to the recovery of hedging costs through the PGA (for LDCs), the recovery of gas hedging costs through the FAC (for electric utilities), and a predetermination of prudency for the gas hedging plans. As the Commission stated in the introduction to the *Gas Procurement Plan General Order*:

> [W]e applaud the efforts of these utilities in their attempt to stabilize fuel costs during this time of very volatile energy prices. We will permit them to proceed with their proposed fuel procurement plans. However, our prior orders and ratemaking treatments ensure that these utilities will not be 'second guessed' in their decisions, as long as prudently made.[52]

The *PGA General Order* reaffirms that both LDCs and electric utilities using natural gas for generation must submit a plan for Commission approval, if they contemplate using financial instruments for natural gas price stabilization:

> Gas utilities must notify the Commission of their rate stabilization programs before the transaction costs or losses associated with the purchase of financial instruments may be recovered through the PGA. Rate stabilization programs which involve the use of financial instruments may be proposed as part of a utility's annual revenue filing. Notification does not constitute approval by the Commission.[53]

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[51] GENERAL ORDER (Jul. 20, 2001), Docket No U-25729, *In re: Louisiana Gas Service Company Rate Stabilization Plan; Trans Louisiana Gas Company PGA Rate Stabilization Plan; Joint Application of Entergy Louisiana, Inc and Entergy Gulf States, Inc. for Prior Approval of a Plan to Employ Risk Management Tools for the Purpose of Stabilizing their Respective Fuel and/or Purchased Gas Adjustment Clauses* ("*Gas Procurement Plan General Order*"), at 9.

[52] *Id.* at 1.

[53] *PGA General Order*, at 12.

For electric utilities, the *Gas Procurement Plan General Order* encourages risk management tools, but does not elaborate on how Electric IOUs should develop any such mechanisms:

> All utilities are encouraged to design plans for the use of risk management tools to meet their particular fuel needs and to accommodate the risks associated with those needs. Any utility that designs such a plan may submit it to the Commission for consideration and approval.[54]

One difference between the above referenced Orders is that LDCs are *required* to submit their plans for risk management tools to the Commission for consideration and approval, whereas other utilities *may* do so. Elaborating on the proposed pre-approvals and advanced prudency determinations, the *Gas Procurement Plan General Order* states:

> [P]re-approval, advanced prudence determination and guaranteed cost recovery are inappropriate. This is true for a variety of reasons. First, that is simply not the way that rate making operates. It is the *utility's* obligation to engage in reasonable and least costs fuel procurement and the Commission's responsibility to determine whether the utility's actions were prudent, *after* those actions are taken... The utilities argue that absent such pre-approval and guaranteed costs recovery, the Commission will, after the fact, exercise hindsight and simply say, for example, "you purchased certain gas at $4.00 per MCF in advance, and on the date of delivery, gas costs were $3.50 per MCF. Therefore, we will find $.50 of your purchase per MCF imprudent." This is precisely the argument advanced by the utilities when the provisions of the [*PGA General Order*] were being discussed as well as in a technical conference to discuss gas rate stabilization issues that was conducted approximately two months ago. On both of those occasions, the utilities were assured by the Staff that it was *not* the Commission's policy to exercise such hindsight.[55]

On the criteria for prudency, the Commission stated the following:

> This Commission could not have been clearer in our assurance that we would *not* second guess gas procurement activities as long as they were prudent *when they were made.* The standard to be applied is whether the utility's gas purchase practices are consistent with what a reasonable gas procurement professional would have done given the information available (*i.e.*, what he knew or should have known) *at the time the gas procurement was made.* Although the plans themselves and the specific actions taken by these utilities in furtherance of these plans will be subject to prudence reviews, if the Commission determines that such reviews are appropriate, these utilities will not be second guessed based upon information that was not known or reasonably knowable at the time the decisions were made.[56]

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54 *Gas Procurement Plan General Order*, at 13.
55 *Id.* at 7, 8 (emphasis in original).
56 *Id.* at 8 (emphasis in original).

There are, however, several significant ambiguities in both the PGA and FAC guidelines for rate stabilization as they relate to long-term, fixed-price contracts. One such ambiguity involves the tradeoff between costs associated with rate stabilization[57] and least cost procurement, as stated in the following provisions of the Orders:

> As a result of these circumstances, it has become increasingly important for both gas and electric utilities to not only perform their public utility obligation to engage in *least cost fuel procurement practices and delivery of safe and reliable service at the lowest reasonable rates, but also to attempt to decrease the volatility in those rates*. Both through our General Orders and our decisions in company-specific cases, the Commission has indicated its support for such measures...
>
> However, the use of hedging tools to stabilize rates must not cause these utilities to lose sight of their utility obligation to provide safe and reliable service at the lowest reasonable cost. If these twin goals are pursued, this Commission will not second guess reasonable and prudent actions of these companies.[58]

What is not indicated, is the degree to which stability of costs and avoidance of potential loses can be substituted for least cost procurement. This, of course, is a very difficult and subjective tradeoff.

The second ambiguity involves timeframe. Although there is no mention of the timeframe appropriate for rate stabilization, most references are to seasonal variations in natural gas prices.[59]

Longer five (5) and ten (10) year timeframes are not explicitly mentioned by these prior Orders, although there is no explicit exclusion of long-term, fixed-price contracts or extended futures contracts and other financial instruments.

Order No. R-26172, Subdocket A (as amended), Development of Market-Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating Capacity to Meeting Native Load: The Commission established a market based mechanism ("MBM") for Louisiana-based electric utilities to evaluate proposals to construct or acquire generating capacity to meet native load needs. Louisiana-based electric utilities have significant history in long-term contracts for

57 *See generally id.* (stating that, in terms of long-term, fixed-price contracts, rate stabilization would constitute a premium over spot purchases).

58 *Id.* at 2, 7(emphasis added).

59 *See id.* at 3 (components of Entergy companies' proposal for one-year hedging program changed according to seasonal variations).

generation capacity and purchased energy from this capacity.[60] The MBM process generally follows the following protocol:

a) A request for proposals ("RFP") competitive solicitation process for capacity and energy resources;

b) If there is an affiliate bid or a self-build option, the MBM process requires a review by an independent monitor to ensure an arms-length transaction and non-preferential treatment;

c) Bids are treated as confidential;

d) Fixed-cost components are included in the Additional Capacity Mechanism of the FRPs for ELL and EGSL, and variable costs and fuel expenses are included in the FAC; and

e) Self-build option: The *MBM General Order* allows utilities to compare market based purchased power agreements ("PPAs") against self-build generation that would be ordinary capital expenditures included in rate base. The criteria for selection of PPAs are multidimensional including least cost and reliability. The least cost attribute is measured by the levelized cost per kWh or (kW for capacity) against the outside contracts. If the self-build option proves to be the competitive least cost solution, the utility can then proceed with certification of the new unit.[61]

On the surface, the MBM process would seem well suited for long-term, fixed-price procurement of natural gas. Procurement for PPAs (for which the MBM process is used), is similar to procurement of natural gas in the following ways: (1) an energy source or supply is procured on an open market (usually through an RFP); (2) the energy contract has price, term and reliability specifications; (3) PPAs have transmission (transportation) costs and delivery point specifications; (4) PPAs can have extended or long-term timeframes; and (5) the self-build option can also be applied to upstream natural gas acquisition and joint partnerships.[62] However,

[60] *See generally* GENERAL ORDER (Oct. 29, 2008), LPSC Docket No. R-26172, Subdocket C (*In re: Possible suspension of, or amendments to, the Commission's General Order dated November 3, 2006 (Market Based Mechanisms Order) to make the process more efficient and to consider allowing the use of on-line auctions for competitive procurement* ("*MBM General Order*")

[61] *See generally id.*

[62] *See generally id.* PPAs are both for capacity and energy. Capacity contracts generally have longer terms than energy contracts, but there are also extended terms for energy provision.

a persistent complaint about the MBM process is that it is too cumbersome, involving a lengthy review process.[63] With regards to the potential application of a course of action similar to the MBM process to long-term, fixed-price natural gas procurement, or other hedging options, several of the parties interviewed stated that the natural gas market changes rapidly, which would render long-term, fixed-price procurement plans irrelevant before they are finalized.

[63] *See generally MBM General Order*, at Attachment A, p.2.

Attachment C: Other States Policies on Long Term Natural Gas Hedging

Several other states have adopted policies to encourage long-term, fixed-price natural gas procurement or gas rate stabilization. These other states include: Colorado, Oklahoma, Oregon, and Florida. The following briefly summarizes each of these states' policies:

i. **Colorado House Bill 10-1365:** This statute encourages the substitution of natural gas combined cycle plants for existing coal-fired units. A component of the bill addresses long-term, fixed-priced natural gas procurement – intended to address a contract between Public Service Company of Colorado and Anadarko Petroleum Company ("Anadarko") to supply natural gas to a newly constructed combined cycle plant. Public Service Company of Colorado issued an RFP for long-term contracts, and then the Company consummated the contract with Anadarko following the execution of a confidentiality agreement by Colorado Public Utility Commission ("CPUC") staff and intervenors. The Colorado legislation and subsequent CPUC ruling has been held as a model for long-term, fixed-price contracting, because: (1) the Colorado legislature memorialized long-term contracts as prudent if competitively procured[64]; and (2) although confidential, the CPUC and its Staff reviewed the contract and gave their approval. The Colorado process has been criticized for involving a lengthy approval process.

ii. **Oklahoma Corporation Commission Rule 165:35-34-1:** This rule adopted and implemented a long-term, fixed-price natural gas contract policy that utilizes an RFP process that is similar, in pertinent substance, to the Louisiana MBM process.[65] Oklahoma has been criticized for having a slow pace of approval. Indeed, many Suppliers interviewed by Staff have noted that the time involved in the approval of a winning response to an RFP would likely outdate the terms of any potential contract.

iii. **Oregon Public Utility Commission Order UM 1520/UG 204:** Northwest Natural Gas Company ("NW Natural"), a natural gas utility, and Encana, Inc. ("Encana"), a natural gas supplier, entered into a joint venture to further develop an established natural gas production facility at the Jonah field in Wyoming.[66] The companies sought approval and a

[64] *See generally* 2010 Colo. House Bill 10-1365.
[65] *Compare* Oklahoma Commission Order 165:35-34-1 *with* the *MBM General Order.*
[66] *See* OPUC Order No. 08-504, Docket UM 1286, as modified by the approval of a stipulation

prudency judgment for the joint venture from the Oregon Public Utility Commission ("OPUC") in Docket UM 1520/UG 204. Under the terms of this joint venture, NW Natural will invest approximately two hundred and fifty million dollars ($250,000,000) in current wells and future drilling. In exchange for this investment, NW Natural can take physical delivery of gas for customer usage, sell the gas on the open market, or allow the supplier to buy the gas at market prices. The revenue requirements of the NW Natural investment will be recovered through Oregon's PGA on ratepayers' bills.[67] The revenue requirement consists of operating expenses, depreciation and depletion, and cost of capital based on NW Natural's approved return on equity ("ROE").[68]

iv. **Florida Public Service Commission Docket No. 140001-EI:** Florida Power and Light Company ("FP&L") and PetroQuest Energy, Inc. entered into a joint venture. The FP&L and Petro Quest joint venture differs from the NW Natural and Encana joint venture in Oregon, in that there is an upfront unregulated affiliate transaction through FP&L that consummated the joint venture with Petro Quest. In December 2014, the Florida Public Service Commission ("FPSC") approved the transfer of operating interest at net book value to FP&L, allowing the natural gas to be available as a utility source of fuel.[69]

v. The Oregon and Florida joint venture arrangements are similar, in that neither state had a general policy established by public utility regulators.[70] Rather, each utility presented the joint venture as a specific action to be approved by their respective regulators. In the case of FP&L, the utility had already consummated the joint venture through an unregulated

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affirmed in OPUC Order No. 11-176, Dockets UM 1520/UG 204, and as further prescribed by the PGA Filing Guidelines, Section VI (1)(d) adopted in the most recent OPUC Order No. 14-238 in Docket UM 1286. Encana subsequently sold its interest in the Jonah facility to TPG Capital.

[67] *See id.* (calculating that unit price as the revenue requirement, divided by the amount of delivered gas).

[68] *See id.* (providing that there would be a reset of the ROE if the OPUC established a new cost of capital for the utility in the rate case). On March 31, 2014, NW Natural executed an amendment to its Carry and Earning Agreement with Encana in order to facilitate Encana's proposed divestiture of its interest in the Jonah field in Wyoming to an affiliate of TPG Capital. The March 31, 2014 agreement ends NW Natural's drilling of wells in the Jonah field, but maintains NW Natural's ownership interest in both existing production as well as a number of future locations. *See* Press Release, "NW Natural Renegotiates Joint Venture With Encana Oil & Gas," *available at* http://www.snl.com/irweblinkx/file.aspx?IID=4057132&FID=22955205.

[69] *See* FPSC Docket 140001, Fuel and purchased power cost recovery clause with generating performance incentive factor (2014).

[70] *Compare* OPUC Order No. 08-504, Docket UM 1286, as modified by the approval of a stipulation affirmed in OPUC Order No. 11-176, Dockets UM 1520/UG 204, and as further prescribed by the PGA Filing Guidelines, Section VI (1)(d) adopted in the most recent Commission Order No. 14-238 in Docket UM 1286, *with* FPSC Docket 140001, Fuel and purchased power cost recovery clause with generating performance incentive factor (2014).

affiliate, and then asked the FPSC to approve an affiliate transaction. The FPSC then approved the transaction in December 2014. An affiliate transaction has a considerable advantage because negotiations do not get bogged down in the regulatory process; however, FP&L's application was filed at the risk that the FPSC would not allow the transfer.

Attachment D: Procedures for Procurement through Request for Proposal

An RFP process is adopted here as an option for long-term natural gas procurement. If an Electric IOU believes that a request for proposal-type process could potentially be the most appropriate procurement process for that Utility's individual needs, then the Utility must indicate as such in its Application.

A. **Procedural Schedule.** The following is a list of the general steps for an RFP process to procure a natural gas cost stabilization instrument:

1. Application filed, LPSC docket opened, decision by Staff on whether to retain consultant(s),draft RFP submitted, Interventions allowed, and Confidentiality Agreement put in place with Staff and Intervenors;
2. Holding of one or more Bidder Conferences and Q&A/Input (including Staff);
3. Comments received for RFP based on input received at Bidder Conferences, Staff, and intervenors;
4. Final RFP issued;
5. RFP results announced;
6. Utility files either: (a) a Request for Certification -and contract(s) seeking approval (if any), with copies to Staff and Intervenors, or (b) a Notification of its inability to procure a long-term natural gas rate stabilization instrument, in accordance with the provisions of Section 3 of the General Order;
7. Upon the filing for a Request for Certification there shall be:
    a. LPSC Publication of certification request, and interventions re-opened for 10 days;
    b. Sixty (60) days shall be allowed for evaluation and testimony by Staff/Intervenors, after receipt of complete contract proposal, including confidential data, and with ten (10) day response period for data requests;[71]
    c. Hearing date; and
    d. LPSC certification.
8. Upon the filing of a Notification there shall be:

[71] The Commission, as needed, may extend the 60-day time limit.

a. A LPSC Publication of the Notification, and interventions re-opened for ten (10) days;

b. Thirty (30) days shall be allowed for evaluation and testimony by Staff/Intervenors, with a ten (10) day response period for data requests;[72]

c. A Hearing date; and

d. A LPSC determination on the acceptance of the Notification

B. Application. An Electric IOU's Application under the RFP process shall consist of an application filed with the Commission that includes the following major categories of information:

a. General Contents. Each Application shall specify, if appropriate to the means of procurement:

1. The Electric IOU's natural gas supply need;
2. The Electric IOU's selected instrument or instruments for gas cost stabilization;
3. A copy of the Electric IOU's Draft RFP;
    a. **Draft RFP.** The soliciting Electric IOU shall prepare and post with the Commission an initial draft of the RFP documents that, to the extent practicable, utilizes industry standard contractual terms and contains all expected material terms and conditions and a solicitation schedule;
    b. **General Contents.** The initial draft of the RFP shall, at a minimum, clearly identify:
        i. Term and Renewals;
        ii. All price and non-price evaluation factors to be considered; and
        iii. The Electric IOU's preliminary analysis of desired delivery points or options as appropriate.
4. The proposed term of a transaction;
5. The volume being considered and rationale for the volume being considered;

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72 The Commission, as needed, may extend the 30-day time limit.

6. The proposed ratemaking treatment for the transaction;
7. Any other potentially related relief that would be consistent with the submitted long-term natural gas procurement program plan;
8. Address security and credit concerns for counterparties;
9. Specify the flexibility of supply origin;
10. Allow for supplier contingencies;
11. Address any required change of law;
12. Describe contract governance for the proposed transaction;
13. Provide quantity minimums and maximums for fuel-based proposals;
14. Describe desired supply type (base load, swing, etc.);
15. Include service level (firm, interruptible, peaking, etc.); and
16. Request delivery point(s) and pipeline(s) while allowing for alternative transportation.

C. <u>**Evaluation of responses to the Request for Proposal.**</u> Evaluation of the responses to the RFP will be conducted by the Electric IOU or LDC as follows:

a. All bids shall be evaluated on the basis of the bidders' final best offers. Bids will be evaluated according to all relevant economic and non-economic factors. No bidder shall be permitted to unilaterally submit a refreshed bid prior to award, unless all bidders are given a meaningful opportunity to submit a refreshed bid as a result of some material, documented change.

b. The soliciting Electric IOU or LDC may request further information from any bidder regarding its bid, provided that any such communication between or among the soliciting Electric IOU or LDC and bidder should be conducted through an open process in which the Electric IOU or LDC and Commission Staff is given adequate notice and an opportunity to attend.

c. In conducting the evaluation of the responses, the soliciting Electric IOU or LDC shall not waive or otherwise modify any evaluation criterion for any bidder.

Attachment E: Procedures for Procurement through Bilateral Negotiations

Several natural gas cost stabilizations instruments (such as fixed-priced, long-term contracts with special delivery provisions, supplier auctions, or joint ventures for upstream supply acquisition), may require detailed negotiations and a degree of confidentiality that cannot be arranged through an RFP process. Because such instruments require a high degree of confidentiality, they do not share the same presumption of market or competitive-based costs as instruments procured through competitive market bidding. Although the Commission recognizes the utility of alternative natural gas procurement methods beyond an RFP process, there must be safeguards that ensure the finalized procurement program plans are fair, competitive with other options, and in the public interest. Procurement of such instruments can proceed through confidential bilateral negotiations, but special consideration must be given to protecting the public interest.

A. **Procedural Schedule.** The following lists the general steps in requesting a bilateral negotiation and approval:

1. Application filed, LPSC docket opened, Decision by Staff on whether to retain consultant, Interventions allowed, and confidentiality agreement put in place with Staff and Intervenors;[73]
2. Minimum sixty (60) days allowed for evaluation and testimony by Staff/Intervenors on Application, after receipt of complete proposal, including confidential data, and with ten (10) day response period for data requests;[74]
3. Hearing date on Application:
4. LPSC determination on Application, the Commission must approve Application before the bilateral negotiations proceed;
5. Private negotiations between parties;
6. Utility files either: (a) a Request for Certification and contract(s) seeking approval (if any), with copies to Staff and Intervenors, or (b) a Notification of its inability to

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[73] Potential counter-parties shall not be allowed to intervene in the Application.

[74] The Commission, as needed, may extend the 60-day time limit (or the utility can suggest a longer period in its Application), depending on the complexity of the Application. The Electric IOU in its Application or an Intervenor after reviewing the Initial Application can request a reasonable extended response time.

procure a long-term natural gas rate stabilization instrument in accordance with the provisions of Section 3 of the General Order;[75]

7. Upon the filing for a Request for Certification there shall be:

   a. LPSC Publication of certification request, and interventions re-opened for 10 days;

   b. Thirty (30) days shall be allowed for evaluation and testimony by Staff/Intervenors, after receipt of complete contract proposal, including confidential data, provided that the contract falls within floor/ceiling prices and terms approved in Application, and with five (5) day response period for data requests;[76]

   c. Alternatively, sixty (60) days shall be allowed for evaluation and testimony by Staff/Intervenors, after receipt of complete contract proposal, including confidential data, if contract does not fall within floor/ceiling prices and terms approved in Application, and with ten (10) day response period for data requests;[77]

   d. Hearing date on Request for Certification; and

   e. LPSC determination.

8. Upon the filing of a Notification there shall be:

   a. A LPSC Publication of the Notification, and interventions re-opened for 10 days;

   b. Thirty (30) days shall be allowed for evaluation and testimony by Staff/Intervenors, with a ten (10) day response period for data requests;[78]

   c. A Hearing date; and

   d. A LPSC determination on the acceptance of the Notification.

B. <u>Application.</u>

a. <u>General Contents.</u> Each Application shall specify, if appropriate:

1. The Electric IOU's or LDC's natural gas supply need;

[75] Counter-parties to contract proposal may intervene in the Final Application
[76] The Commission, as needed, may extend the 30-day time limit.
[77] The Commission, as needed, may extend the 60-day time limit.
[78] The Commission, as needed, may extend the 30-day time limit.

2. The Electric IOU's or LDC's selected instrument or instruments for gas cost stabilization;
3. A proposal on deliverables and required performance criteria by the counterparty (Supplier);
4. A selection process for a counterparty;
5. The proposed term of a bilateral agreement;
6. Estimated costs associated with a bilateral agreement;
7. The volume being considered and rationale for the volume being considered;
8. The proposed ratemaking treatment for the bilateral agreement;
9. Any other potentially related relief that would be consistent with the submitted long-term natural gas procurement program plan.
10. Address security and credit concerns for counterparties;
11. Specify the flexibility of supply origin;
12. Allow for supplier contingencies;
13. Address any required change of law;
14. Describe dispute resolution processes for the proposed bilateral agreement;
15. Request delivery point(s) and pipeline(s) while allowing for alternative transportation; and
16. Any other substantial evidence that the bilaterally negotiated procurement program plan is a reasonable option, relative to other equivalent long-term natural gas procurement program plans.

C. **Private Negotiations between Parties.** Upon the commencement of the negotiations, Staff and intervenors shall be made privy to:

1. Regular progress reports; and
2. Final transaction documents.

D. **<u>Request for Certification.</u>** Upon completion of negotiations, the Electric IOU or LDC shall file a Request for Certification and contract(s) seeking approval (if any), with copies to Staff and Intervenors.

The expedited, streamlined procedures for the evaluation of long-term natural gas supply contract proposals provided for within the other sections of this Order shall not be utilized for the evaluation or approval of any Request for Certification submitted pursuant to the Long-term Procurement Pilot Program seeking to acquire ownership in natural gas reserves, either through direct ownership, joint ventures for upstream supply acquisitions, or otherwise; rather, any such Request for Certification that includes a proposal to acquire ownership in natural gas reserves shall be evaluated by the LPSC according to the Commission's standard rules of practice and procedure.[79]

a. **<u>General Contents.</u>** At a minimum, each Request for Certifications seeking approval of any specific transaction that meets the requirements of an Application shall include the following:

1. An overview of the subject transaction;
2. All final and/or final drafts of legal and financial documents and agreements; and
3. An analysis comparing the preliminary specifications outlined and approved in the Electric IOU's or LDC's Application with those of the subject transaction in the Request for Certification, explaining how the individual specifications of the bilateral agreement in the Request for Certification meets or exceeds the requirements stated in the Electric IOU's or LDC's Application.

[79] Nevertheless, such proposals in a utility's Application shall satisfy the reasonable efforts participation requirements of the Long-term Procurement Pilot Program.

Attachment F: Procedures for Procurement through Long-term Hedges or Futures Contract Purchases on Recognized Exchanges

Long-term financial hedging and futures contracts require Electric IOUs and LDCs to. In their Application, an Electric IOU or LDC shall specify current market conditions, current market prices, and acceptable ranges for final procurement program prices.

A. **Procedural Schedule.** The following is a list of the general steps to procure long-term natural gas hedges or futures contracts:

1. LPSC docket opened, Decision by Staff on whether to retain consultant, Interventions allowed, and Confidentiality Agreement put in place with Staff and Intervenors;
2. Utility files Application, including proposed plan;
3. Review of Application, with minimum of sixty (60) days allowed for evaluation and testimony by Staff/Intervenors, after receipt of complete proposal, including confidential data, and with ten (10) day response period for data requests;[80]
4. Hearing date on Application;
5. Approval of Application;
6. Procurement;

7. Utility files either: (a) a Request for Certification and contract(s) seeking approval (if any), with copies to Staff and Intervenors, or (b) a Notification of its inability to procure a long-term natural gas rate stabilization instrument in accordance with the provisions of Section 3 of the General Order;[81]
8. Upon the filing for a Request for Certification there shall be:
   a. LPSC Publication of certification request, and interventions re-opened for ten (10) days;
   b. Thirty (30) days shall be allowed for evaluation and testimony by Staff/Intervenors, after receipt of complete contract proposal, including confidential data, provided that the contract falls within floor/ceiling prices and terms approved in Application, and with five (5) day response period for data requests;[82]

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80 The Commission, as needed, may extend the 60-day time limit.
81 Counter-parties to contract proposal may intervene in the Final Application.
82 The Commission, as needed, may extend the 30-day time limit.

c. Alternatively, sixty (60) days shall be allowed for evaluation and testimony by Staff/Intervenors, after receipt of complete contract proposal, including confidential data, if contract does not fall within floor/ceiling prices and terms approved in Application, and with ten (10) day response period for data requests;[83]

d. Hearing date on Request for Certification; and

e. LPSC determination.

9. Upon the filing of a Notification there shall be:

a. A LPSC Publication of the Notification, and interventions re-opened for ten (10) days;

b. Thirty (30) days shall be allowed for evaluation and testimony by Staff/Intervenors, with a ten (10) day response period for data requests;[84]

c. A Hearing date; and

d. A LPSC determination on the acceptance of the Notification

B. <u>Long-term Hedges or Futures Application.</u> An Electric IOU's or LDC's Application shall consist of an application filed with the Commission that includes the following major categories of information:

a. <u>General Contents.</u> At a minimum, each Application shall specify:

1. The Electric IOU's or LDC's natural gas supply need;
2. The Electric IOU's or LDC's rationale for choosing the procurement through long-term hedges or futures;
3. The proposed term of a transaction;
4. Estimated costs associated with a transaction;
5. The volume being considered and rationale for the volume being considered;
6. Current and projected market prices for the hedge;
7. A range of market price variances, around which the actual price procured would still be acceptable under the terms of the Application;

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[83] The Commission, as needed, may extend the 60-day time limit.
[84] The Commission, as needed, may extend the 30-day time limit.

8. How the Electric IOU or LDC plans to address default risk, credit support, and collateral management associated with the instrument;
9. The proposed ratemaking treatment for the transaction; and
10. Substantial evidence that the procurement program plan is a reasonable option, relative to other equivalent long-term natural gas procurement program plans; and
11. For OTC Swaps, the Application shall include a risk management plan.

b. **<u>Financial Hedging Safeguards.</u>** As part of its Application, Electric IOUs and LDCs that propose to utilize financial hedging as their long-term natural gas cost stabilization instrument shall also be required to include in their Applications a detailed narrative of their plans to address risk governance, counterparty default risk, credit support and collateral management associated with the instrument. These additional requirements are divided into the following sections, based on long-term natural gas cost stabilization instrument type: (i) Risk Management for hedged physical delivery; and (ii) futures and basis contracts.

i. **Risk Management for hedged physical delivery:**

1. There are a number of different options to provide for physical delivery of natural gas with an adjoining financial hedge for price stability. Usually, such operations involve the implementation of several simultaneous, or near simultaneous, structured transactions:
   a. A primary supply contract that is indexed to the Henry Hub;
   b. A basis contract from Henry Hub to the receipt point;
   c. A commodity swap with an indexed to fixed-price swap;[85] and
   d. An underwriting contract with a clearing house.[86]

[85] The commodity swap market is regulated by the Commodity Futures Trading Commission and is subject to the provisions of the Dodd-Frank Act, although a partial exemption exists for Utilities that are regulated by Public Service Commissions and qualify as "end-users" rather than swap dealers.

[86] There are a limited number of clearing houses in the Unites States that facilitate such transactions, usually large financial institutions based in New York. The clearing house is a financial institution that acts as a

If an Electric IOU or LDC proposes to use one of the above types of long-term natural gas cost stabilization instruments in its Application, the Electric IOU or LDC shall include in its Application the details of its plans to:

a. Establish a Risk Governance Policy and oversight procedure governed by a management committee that describes the categories and degrees of risks acceptable to the Electric IOU or LDC, as well as how it plans to manage and report these risks. The committee or individual responsible for implementation of the Risk Governance Policy shall also be identified in the Application. This structure will provide the Commission with transparency regarding the risk policies and cost structure(s) of the long-term hedges.

b. *Define permitted transaction types.* An Electric IOU or LDC shall detail the structured, layered transaction in the Application. The Electric IOU or LDC shall describe the following:

    a. The supply contract with a natural gas supplier. The description shall specify the period of years (five-year or more) and pricing (usually against a floating natural gas price index).

    b. The options available for delivery. A typical contract shall involve pricing for a month's delivery taking place on the last five (5) working days ("bid week") of the

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market participant who is taking the risk of the counterparty default and ensures that the payments are performed even in case of default. Once the trade is changed from bilateral to the trade with the clearing house, it is considered a cleared trade. To manage the risk of default, the clearing house requires primary parties to hold margin at the clearing house to cover its unsettled positions and the clearing house will monitor this margin level to make sure that it covers outstanding trades. A clearing house reduces the settlement risks by netting offsetting transactions between multiple counterparties, by requiring collateral deposits (also called "margin deposits"), by providing independent valuation of trades and collateral, by monitoring the credit worthiness of the clearing firms, and in many cases, by providing a guarantee fund that can be used to cover losses that exceed a defaulting clearing firm's collateral on deposit.

month prior to the delivery month. A typical contract payment shall occur on the twentieth (20th) day of the following month.

c. The existence of any separate agreements. The descriptions shall include details of any separate agreements with other counterparties for a basis contract for physical delivery at a point other than the Henry Hub.[87]

d. The swap mechanism. The descriptions shall include details of how the original supply contract is then to be swapped through a financial derivative contract into a fixed-price contract.[88]

c. Approve and authorize an executor/clearing house. Underwriting by a clearing house for one of these types of transactions is not a necessity; however, if an Electric IOU or LDC does not secure an underwriter, then that Utility shall fully justify measures that counteract the risk of default and adverse price trends. If a clearing house broker is to be used, there shall be a presumption that the clearing house uses competitive market assessment to secure counterparties and underwrite default and credit risk. However, the Electric IOU or LDC shall still be required to justify clearing house fees and premiums as reasonable expenses.

e. Establish criteria for both initial and ongoing counterparty credit-worthiness assessments.

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87 Such basis contracts rarely exceed a 3-5 year period due to credit considerations.

88 Although a liquid, ten (10) year HH market exists, credit considerations have made it difficult to conclude transactions economically beyond the initial 3-5 year period.

f. Establish policies and procedures for transparency in the reporting of forward swap contract commitments ("positions") and financial exposures.

g. Establish methodologies, policies and procedures for mark to market calculations and segregated collateral cash management protocols. Financial-based, long-term contracts may be subject to "mark to market" stipulations, which require an assessment of the potential liability costs of defaulting on the contract vis-à-vis current market natural gas prices. These assessments occur at certain regular intervals. A party that incurs a mark to market loss may be required by a counterparty to a trade to provide collateral as surety against non-performance or default. Counterparties may be required to post some form of previously agreed to and Commission-approved security where a mark to market loss resides.[89] In transactions that are exchange cleared, the surety shall be demanded through a margin call and shall be held on deposit at a specified clearing corporation. As the margin call or collateral is a demand for capital, an Electric IOU or LDC may submit the requirement as part of working capital in rate base at the Electric IOU's or LDC's approved cost of capital. If no collateral agreement is contemplated, the Supplier shall take the possibility of non-performance into consideration when calculating a sales price. This can also be done by purchasing a financial instrument known as a credit default

[89] For example, assume that a long-term, fixed-price contract has a price of $5.00 per MMBtu. Current market prices are $4.00. There is incentive or probability for the buyer (utility) to default on the contract (although this is not likely because the cost of gas is passed through the FAC). A percentage of the outstanding liability may be required as collateral by the counterparty and/or clearing house.

swap on an Electric IOU or LDC, which pays the purchasing party in the event of the counterparty's default.

h. Establish and implement value and liquidity market tracking metrics and policies and procedures for monitoring stop-loss thresholds.

i. Establish policies, procedures, and monitoring mechanisms for Federal and state compliance reporting and regulatory audits (e.g., the Dodd-Frank Act, if required).

j. Establish policies and procedures for transparency in the reporting of positions and financial exposures.

ii. Futures and basis contracts:

1. Futures contracts and OTC basis contracts shall be a structured transaction and require the same risk management policies and justification indicated in Section 3(a)(ii)(1) above. Any contingencies, such as the requirements by exchanges or brokerage houses for collateral and margin calls under adverse price trends, shall be addressed in the risk governance plan and management outlined above.

C. **Long-term Hedges or Futures Request for Certification.** Upon the procurement of such instruments, the Electric IOU or LDC shall file a Request for Certification that complies with the content requirements for Request for Certifications (as found in this Order), in accordance with the review and approval schedule approved in the Electric IOU's or LDC's Application.

a. **General Contents.** At a minimum, each Request for Certifications seeking approval of any specific transaction that meets the requirements of an Application shall include the following:

1. An overview of the subject transaction;
2. An analysis comparing the preliminary specifications outlined and approved in the Electric IOU's or LDC's Application with those of the subject transaction in the Request for Certification, explaining how the individual specifications and prices of the subject

transaction in the Request for Certification meets or exceeds the requirements stated in the Electric IOU's or LDC's Application.

SOUTHWESTERN ELECTRIC POWER COMPANY, EX PARTE.

U-34354

Louisiana Public Service Commission

August 25, 2017

BY THE COMMISSION.

In re: Application for Approval of Long Term Natural Gas Procurement Proposal.

(Decided at the Business and Executive Session held on July 26, 2017.)

Overview

***1** This matter came before the Louisiana Public Service Commission ("Commission" or ""LPSC") for consideration of a *Proposed Stipulated Settlement. Pursuant to Rule 57* filed jointly by SWEPCO and Commission Staff on July 14, 2017. The Commission approved the stipulated settlement, authorizing the Company's Request for Certification of Long-Term Natural Gas Contract with the lowest bidder, pursuant to General Order R-32975. based upon and subject to certain terms and conditions contained therein.

Jurisdiction and Applicable Law

The Commission exercises jurisdiction in this proceeding pursuant to Article IV, Section 21(B) of the Louisiana Constitution and LPSC Order No. R-32975. dated July 13, 2015.

La. Const. Art. IV, Sec. 21 provides in pertinent part:

(B.) The commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by law. It shall adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties, and shall have other powers and perform other duties as provided by law.

This Commission approved the implementation of a Long-Term Natural Gas Procurement Pilot Program ("Pilot Program") in Order No. R-32975, dated July 13, 2015 ("LTHP Order"), requiring jurisdictional Electric IOUs to propose long-term natural gas procurement programs for the purpose of securing long-term natural gas price stability. Further, the LTHP Order requires Louisiana-jurisdictional electric utility companies to explore the feasibility of procuring long-term natural gas resources through a combination of cost stabilization instruments identified in the Order, and to propose the procurement of three long-term natural gas procurement programs. The LTHP Order defines three procurement methods: 1) request for proposal ("RFP"), 2) bilateral negotiation, and 3) purchased through established exchanges or over the counter ("OTC"). The Order also requires Electric IOUs to file a Request for Certification of the chosen procurement method.

Procedural History

On January 24, 2017, Southwestern Electric Power Company ("SWEPCO" or the ""Company") filed its *Application of Southwestern Electric Power Company for Approval of Long-Term Natural Gas Procurement Request for Proposals in Accordance with the Commission's General Order R-32975.* Notice of the Application was published in the Commission's Official Bulletin No. 1141. dated January 27, 2017.[1]

1 Entergy Louisiana, LLC originally intervened, but filed a *Notice of Withdrawal* on July 12, 2017, formally withdrawing its

intervention. No other interventions were filed.

*2 A Technical Conference was conducted on March 6, 2017 to discuss the implementation of the Long-Term Natural Gas Hedging Proposal filed by SWEPCO. SWEPCO issued its Request for Proposals ("RFP") on April 27, 2017. In its RFP, SWEPCO sought to secure a reliable supply of natural gas and requested up to 15,000 MMBtu/Day, as set forth in their RFP. for the Company's J. Lamar Stall Plant ("Stall Plant") located near downtown Shreveport. The 508 MW Stall Plant is a combined-cycle natural gas-fired power plant with a high capacity factor, which came on line in 2010. The gas supply could also be used to serve four other SWEPCO gas-fired generation facilities that operate as peaking units along the same interstate pipeline, which is operated by Enable Gas Transmission. LLC. These facilities include the Wilkes, Mattison, Lone Star, and Lieberman plants. The Company's natural gas supply RFP requested a term of five (5) years, beginning on April 1, 2018. and expiring on March 31, 2023. Proposals were accepted until May 17, 2017. SWEPCO received three qualifying bids for long-term natural gas supply contracts.

On June 28, 2017, SWEPCO filed its *Request for Certification of Long-Term Natural Gas Contract* ("Request"), with attached testimony, which was published in the Commission's Official Bulletin dated June 30, 2017 under Docket No. U-34502 for a 10-day intervention period pursuant to *Attachment D* of the LMTP Order. No interventions were filed. Docket No. U-34502 was consolidated into Docket No. U-34354 in the Commission's Official Bulletin, dated July 14, 2017.[2]

[2] The Company's *Request for Certification* was mistakenly filed into a new docket, where a 10-day intervention period was re-opened, pursuant to *Paragraph 7(a) to Attachment D of the LTHP Order.* The consolidation notice in the Commission's Official Bulletin corrects this error.

On July 14, 2017, Staff and SWEPCO filed a *Joint Motion for Commission Consideration of Proposed Stipulated Settlement, Pursuant to Rule 57* and executed the *Proposed Stipulated Settlement*, which all parties believed to be reasonable in light of the record, in the public interest, and effectively resolved all issues in the proceeding.

Stipulated Settlement

In the *Proposed Stipulated Settlement*, Staff and SWEPCO agreed that the Company's Request should be authorized, based upon and subject to the following:
1. The Company's Application, RFP, and its Request for Certification submitted in this docket are in compliance with the provisions of *LTHP Order.*

2. To maintain compliance with the provisions of the *LTHP Order*, SWEPCO should file, in a subsequent request in Docket No. U-34354, a *Notification of Inability to Procure* for the long-term natural gas cost stabilization instruments not selected from its RFP.

*3 3. Staff has agreed to waive the time delays outlined in *Paragraph 7* to *Attachment D* to the *LTHP Order* in order for SWEPCO to take advantage of the favorable pricing and contractual terms. This expedited treatment includes a waiver of the 60-day evaluation period and consideration by the Commission at its July 26, 2017 Business and Executive Session.

4. Staff and SWEPCO recommend that the Commission include, in its Order, the prudence of SWEPCO's contract and authorizing recovery of all costs associated with any Commission approved natural gas supply contracts through its Fuel Adjustment Clause ("FAC"), in compliance with the *LTHP Order*, subject to the following:

a. With regards to the fixed price contract, the final price shall not exceed ten percent (10%) of the price offer received in the RFP;

b. With regards to the costless collar, neither the put, nor the call prices (i.e. ceiling and floor) shall exceed ten percent (10%) of the ceiling and floor offers received in the RFP; and

c. The following monitoring and reporting procedures shall be established, allowing Staff to remain apprised of any contract for instruments' performance:

i. The Company shall include these instruments in its monthly fuel filings, pursuant to its FAC, which would show the monthly fuel purchases by supplier, subject to the necessary confidentiality;

ii. The Company will make semi-annual confidential filings as to the performance under these contracts. These semi-annual confidential filings shall be made at the end of the summer and winter seasons. These semi-annual confidential filings shall include, but shall not be limited to. the following information:

1. Daily quantities and prices executed under the instruments:

2. The manner in which all gas procured under these instruments was utilized (i.e. the gas was used at Stall, or an explanation of how it was otherwise utilized or disposed);

3. A comparison of the fixed price against other prices paid for natural gas during the period (e.g. compared against any spot price purchases and/or compared against other monthly or short-term purchasing strategies); and

4. All executions of the calls and puts and the gains and losses realized from such executions.

Commission Consideration

The *Proposed Stipulated Settlement* was considered by the Commission at its July 26, 2017 Business and Executive Session. On motion of Chairman Skrmetta, seconded by Commissioner Campbell, and unanimously adopted, the Commission voted to assert its original and primary jurisdiction and take the matter up pursuant to Rule 57.

On motion of Chairman Skrmetta, seconded by Commissioner Campbell, and unanimously adopted, the Commission voted to accept the *Proposed Stipulated Settlement* executed on July 14, 2017, approving SWEPCO's Request for Certification of Long-Term Natural Gas Contract with the lowest bidder, pursuant to General Order R-32975, and subject to the terms and conditions listed in the *Stipulated Settlement.*

***4 IT IS THEREFORE ORDERED THAT:**

1. The Stipulated Settlement executed on July 14, 2017 between Staff and SWEPCO is approved; and

2. This Order is effective immediately.

BY ORDER OF THE COMMISSION BATON ROUGE, LOUISIANA

ERIC F. SKRMETTA

DISTRICT I

CHAIRMAN ERIC F. SKRMETTA

LAMBERT C. BOISSIERE

DISTRICT III

VICE CHAIRMAN LAMBERT C. BOISSIERE

FOSTER L. CAMPBELL

DISTRICT V

COMMISSIONER FOSTER L. CAMPBELL

MIKE FRANCIS

DISTRICT IV

COMMISSIONER MIKE FRANCIS

DAMON J. BALDONE

DISTRICT II

COMMISSIONER DAMON J. BALDONE

EVE KAHAO GONZALEZ

SECRETARY

SOAH DOCKET NO. 473-19-6862
PUC DOCKET NO. 49737

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-14:

Identify other utilities who have initiated natural gas price hedging programs similar in scope and financial scale to the investment associated with the proposed wind energy facilities in this case.

Response No. 2-14:

See the Company's response to CARD 2-13.

Prepared By: Jonathan M. Griffin	Title: Regulatory Consultant Staff
Prepared By: Lynn M. Ferry-Nelson	Title: Dir Regulatory Svcs
Sponsored By: Thomas P. Brice	Title: VP Regulatory & Finance

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-15:

Explain the basis for the level of wind energy resources which SWEPCO proposes to acquire in this case and provide any analyses of costs and benefits of lower or higher levels of wind resource acquisitions considered by the Company.

Response No. 2-15:

Please see page 20 of the Direct Testimony of Jay F. Godfrey and Section III of the Direct Testimony of John F. Torpey. SWEPCO only prepared customer benefits analyses for acquisitions of 810 MW.

Prepared By: Edward J. Locigno	Title: Regulatory Analysis & Case Mgr
Prepared By: Paul N. Demmy	Title: Resource Planning Anlyst Sr
Prepared By: Jon R. Maclean	Title: Resource Planning Mgr
Prepared By: William S. Robinson	Title: Resource Planning Anlyst Staff
Prepared By: James F. Martin	Title: Regulatory Case Mgr
Sponsored By: Jay F. Godfrey	Title: VP Energy Mktng & Renewables
Sponsored By: John F. Torpey	Title: Mng Dir Res Plnning&Op Anlysis

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-16:

Provide SWEPCO's system weighted average cost of gas ($/MMBtu) for each month since January 2016 and as forecasted for each month of the first five years of the base case modeling analyses supporting the proposed wind energy resources.

Response No. 2-16:

See CARD 2-16 Attachment 1.xlsx

Prepared By: Paul N. Demmy	Title: Resource Planning Anlyst Sr
Prepared By: Jon R. Maclean	Title: Resource Planning Mgr
Prepared By: William S. Robinson	Title: Resource Planning Anlyst Staff
Prepared By: James F. Martin	Title: Regulatory Case Mgr
Sponsored By: John F. Torpey	Title: Mng Dir Res Plnning&Op Anlysis

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-17:

Provide SWEPCO's system average cost of SPP market energy purchases ($/MWh) for each month since January 2016 and as forecasted for each month of the first five years of the base case modeling analyses supporting the proposed wind energy resources.

Response No. 2-17:

See CARD 2-17 Attachment 1.xlsx

Prepared By: Paul N. Demmy — Title: Resource Planning Anlyst Sr
Prepared By: Jon R. Maclean — Title: Resource Planning Mgr
Prepared By: William S. Robinson — Title: Resource Planning Anlyst Staff
Prepared By: James F. Martin — Title: Regulatory Case Mgr

Sponsored By: John F. Torpey — Title: Mng Dir Res Plnning&Op Anlysis

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-18:

Provide SWEPCO's system average cost of SPP market energy purchases ($/MWh) during daily on-peak hours for each month since January 2016 and as forecasted for each month of the first five years of the base case modeling analyses supporting the proposed wind energy resources.

Response No. 2-18:

See CARD 2-18 Attachment 1.xlsx

Prepared By: Paul N. Demmy	Title: Resource Planning Anlyst Sr
Prepared By: Jon R. Maclean	Title: Resource Planning Mgr
Prepared By: William S. Robinson	Title: Resource Planning Anlyst Staff
Prepared By: James F. Martin	Title: Regulatory Case Mgr
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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-19:

Provide SWEPCO's system average cost of SPP market energy purchases ($/MWh) during daily off-peak hours for each month since January 2016 and as forecasted for each month of the first five years of the base case modeling analyses supporting the proposed wind energy resources.

Response No. 2-19:

See CARD 2-19 Attachment 1.xlsx

Prepared By: Paul N. Demmy	Title: Resource Planning Anlyst Sr
Prepared By: Jon R. Maclean	Title: Resource Planning Mgr
Prepared By: William S. Robinson	Title: Resource Planning Anlyst Staff
Prepared By: James F. Martin	Title: Regulatory Case Mgr
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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION

Question No. 2-20:

Identify and explain the basis for any revisions made by SWEPCO to the input data set for the SPP market for the base case modeling analyses supporting the proposed wind energy resources.

Response No. 2-20:

SWEPCO relied on SPP's 2019 ITP PROMOD Reference Case model, but made a few modifications. For the Bid Evaluation analysis, these modifications were to account for the addition of 4,400 MW of RFP bids to the SPP 2019 ITP model. Please see the discussion at pp. 17-21 of witness Pfeifenberger's testimony for additional details. For the customer benefits analysis of the Selected Wind Facilities, see discussion at pp. 29-31 of witness Pfeifenberger's testimony, which explains the additional modeling refinements made, and the reasonableness of these refinements for the purpose of the Company's customer benefits analysis.

Prepared by: Cecile Bourbonnais — Title: Research Analyst, The Brattle Group
Prepared by: Sophie Leamon — Title: Research Analyst, The Brattle Group

Sponsored by: Akarsh Sheilendranath — Title: Senior Associate, The Brattle Group

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<u>SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES ADVOCATING REASONABLE DEREGULATION'S SECOND SET OF REQUESTS FOR INFORMATION</u>

Question No. 2-21:

Provide the commercial operation dates, assumed retirement dates, and net dependable capacity ratings (MW) of each existing and new SWEPCO generating resource included in the base case modeling analyses supporting the proposed wind energy resources.

Response No. 2-21:

See CARD 2-21 Attachment 1.

Prepared By: Paul N. Demmy	Title: Resource Planning Anlyst Sr
Prepared By: Jon R. Maclean	Title: Resource Planning Mgr
Prepared By: William S. Robinson	Title: Resource Planning Anlyst Staff
Prepared By: James F. Martin	Title: Regulatory Case Mgr
Sponsored By: John F. Torpey	Title: Mng Dir Res Plnning&Op Anlysis

Existing SWEPCO Units

Plant	Fuel	Year Installed	Retirement Year	Life Span (Years)	MW Rating
Dolet Hills					
Unit 1	Lignite	1986	2046	60	262
Flint Creek					
Unit 1	Coal	1978	2038	60	264
Pirkey					
Unit 1	Lignite	1985	2045	60	580
Turk					
Unit 1	Coal	2012	2067	55	650
Welsh					
Unit 1	Coal	1977	2037	60	528
Unit 3	Coal	1982	2042	60	528
Arsenal Hill					
Unit 5	Natural Gas	1960	2025	65	110
Stall					
Unit 6A	Natural Gas (CC)	2010	2050	40	511
Unit 6B	Natural Gas (CC)	2010	2050	40	511
Unit 6S	Natural Gas (CC)	2010	2050	40	511
Knox Lee					
Unit 2	Natural Gas	1950	2019	69	30
Unit 3	Natural Gas	1952	2019	67	31
Unit 4	Natural Gas	1956	2019	63	79
Unit 5	Natural Gas	1974	2039	65	348
Lieberman					
Unit 2	Natural Gas	1949	2019	70	26
Unit 3	Natural Gas	1957	2022	65	109
Unit 4	Natural Gas	1959	2024	65	108
Lone Star					
Unit 1	Natural Gas	1954	2019	65	50
Mattison					
Unit 1	Natural Gas (CT)	2007	2052	45	76
Unit 2	Natural Gas (CT)	2007	2052	45	76
Unit 3	Natural Gas (CT)	2007	2052	45	76
Unit 4	Natural Gas (CT)	2007	2052	45	76
Wilkes					
Unit 1	Natural Gas	1964	2029	65	177
Unit 2	Natural Gas	1970	2035	65	362
Unit 3	Natural Gas	1971	2036	65	362

2019 SWEPCO Wind RFP Analysis
Brattle Base Band Commodity Pricing
SWEPCO Optimal Expansion Plan (Supply-side, Renewables, ST PPA) Assuming Wind RFP Additions and ELCC Based Renewable Firm Capacity Credits

Firm Capacity (MW)

Date	HA.02 CC	SW_ Dist Gen	SW_Wind Year 2024	SW_Wind Year 2029	SW_Wind Year 2047	Utility Solar Tier 1- 2027	Utility Solar Tier 1- 2028	Utility Solar Tier 1- 2029	Utility Solar Tier 1- 2030	Utility Solar Tier 1- 2031	Utility Solar Tier 1- 2032	Utility Solar Tier 1- 2033	Utility Solar Tier 1- 2034	Utility Solar Tier 2- 2029	Utility Solar Tier 2- 2030	SWP ST PPA
2020	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	12	200	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	13	200	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	14	200	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	14	200	0	0	150	0	0	0	0	0	0	0	0	0	0
2028	0	15	200	0	0	150	150	0	0	0	0	0	0	0	0	0
2029	0	15	200	600	0	150	150	150	0	0	0	0	0	150	0	0
2030	0	16	200	600	0	150	150	150	150	0	0	0	0	150	150	0
2031	0	17	200	600	0	150	150	150	150	150	0	0	0	150	150	0
2032	0	18	200	600	0	150	150	150	150	150	150	0	0	150	150	0
2033	0	18	200	600	0	150	150	150	150	150	150	150	0	150	150	0
2034	0	19	200	600	0	150	150	150	150	150	150	150	150	150	150	0
2035	0	20	200	600	0	150	150	150	150	150	150	150	150	150	150	0
2036	0	21	200	600	0	150	150	150	150	150	150	150	150	150	150	0
2037	0	22	200	600	0	150	150	150	150	150	150	150	150	150	150	100
2038	302	23	200	600	0	150	150	150	150	150	150	150	150	150	150	250
2039	604	24	200	600	0	150	150	150	150	150	150	150	150	150	150	150
2040	906	25	200	600	0	150	150	150	150	150	150	150	150	150	150	150
2041	906	26	200	600	0	150	150	150	150	150	150	150	150	150	150	150
2042	906	27	200	600	0	150	150	150	150	150	150	150	150	150	150	200
2043	1510	28	200	600	0	150	150	150	150	150	150	150	150	150	150	0
2044	1510	29	200	600	0	150	150	150	150	150	150	150	150	150	150	0
2045	1510	30	200	600	0	150	150	150	150	150	150	150	150	150	150	100
2046	2114	32	200	600	0	150	150	150	150	150	150	150	150	150	150	0
2047	2114	33	200	600	200	150	150	150	150	150	150	150	150	150	150	250
2048	2114	34	200	600	200	150	150	150	150	150	150	150	150	150	150	250
2049	2416	36	200	600	200	150	150	150	150	150	150	150	150	150	150	0
2050	2416	37	200	600	200	150	150	150	150	150	150	150	150	150	150	0
2051	2718	39	200	600	200	150	150	150	150	150	150	150	150	150	150	100